THE SCIENCE OF PETROLEUM

VOLUME I

THE SCIENCE OF PETROLEUM

A COMPREHENSIVE TREATISE OF THE PRINCIPLES AND PRACTICE OF THE PRODUCTION REFINING TRANSPORT AND DISTRIBUTION OF MINERAL OIL

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FOREWORD

BY

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Past President of the Institution of Petroleum Technologists.

IT is with great pleasure that I contribute this foreword to the SCIENCE OF PETROLEUM, because I have, on many occasions, stressed the overwhelming importance of science in industry.

In no branch of human endeavour has the application of exact knowledge been so apparent as in the exploring, winning, refining, transport, distribution, and utilization of mineral oil. At every point in the long road that leads from the oil well to the consumer investigation and research have been employed with almost spectacular results.

The world to-day would be immobilized without copious supplies of the derivatives of petroleum. On the ground, in the air, on the surface of the waters and under the sea speedy transport is provided. Both in peace and in war oil is a unique necessity. The lamp in the cottage, the stove in the kitchen, the incubator at the farm, the omnipresent candle in the home, the asphalt surface of the road, the innumerable varieties of lubricants in every factory, machine, and prime mover—in every direction in our modern civilization oil plays its part.

In the following pages are given the latest developments of every phase of the industry, and there is displayed in almost every section the impact of current scientific thought on the multitudinous problems that are arising almost day by day. The whole work gives a vivid and comprehensive picture of present activities and future possibilities.

PREFACE

THE petroleum industry may be said to have originated with the discovery of an efficient commercial method of producing burning oil. There were several attempts to do this on a small scale in the early part of the nineteenth century, but none of these was of any commercial importance until Selligue produced shale oil in France in 1838 and James Young started in 1848 to refine crude petroleum from the Riddings Colliery in Derbyshire, and subsequently applied his well-known process to torbanite and oil shales. The commercial success of his process encouraged the search for crude petroleum in the United States of America, and the discovery of the Drake Oil Well in 1859 initiated the American petroleum industry. For many years the main products of the industry were burning oil and crude lubricants, and it is only during the present century that the petroleum industry has become one of the major industries of the world. In 1900 the motor-car was still a curiosity; marine turbine and Diesel engines were in their infancy; and aeroplanes did not exist. To-day the annual production of oil exceeds 240,000,000 tons; there are nearly 40 million motor vehicles on the roads; more than half the ships of the world are fuelled with oil; and air transport has become almost commonplace. Indeed, the exploitation of oil has brought about in the twentieth century a revolution quite as great in its consequences as the industrial revolution of the nineteenth century; and if we are sometimes acutely conscious that it has added to the problems and dangers of modern civilization, we should not forget that it has brought occupation and happiness to many millions of people.

Science has played an important and indispensable part in the development of the oil industry. Forty years ago the methods of winning and refining oil were wasteful to a degree which would be thought intolerable to-day. The volatile constituents of petroleum were then but a dangerous by-product in the manufacture of burning oil which was obtained from the crude oil by simple distillation. But soon the rapid growth of the automobile industry created a demand for the volatile fractions which could not be met by straightforward distillation of petroleum. Laboratory research had already shown on a small scale that the high-boiling constituents of natural oil could be converted by heating into volatile fractions. Burton, in the United States, applied this knowledge on the commercial scale, and can justly be regarded as the pioneer of the modern cracking industry. The results of his work have been remarkable. Even in 1912 only 13 per cent. of crude petroleum was sold as motor spirit; to-day the proportion is 50 per cent. Immense units capable of processing 10,000 tons of crude a day are becoming common; and in one commercial operation oil is separated into a range of motor spirits, burning oils, gas oils, lubricating oils, and residue, under accurately controlled conditions which vary according to the nature and quantity of the products required.

The 'cracking' of petroleum by thermal decomposition was first employed merely to increase the quantity of light spirit available; but in recent years quality has been a prime consideration. In the early motor-cars thermal efficiency was of no great importance, and cylinder pressures were limited by purely engineering difficulties. For these reasons the importance of the chemical nature of the fuel used was not recognized. But with the advent of the aircraft engine, thermal efficiency became of great importance, cylinder pressures were consequently increased; and the engineer, having solved his own

immediate mechanical problems, found that further advances were limited by the quality of the fuel available, owing to its tendency to detonate or 'knock'. It was soon conclusively shown by experiments that the tendency to knock varied considerably with the nature of the hydrocarbon constituents of light fuel, and, in particular, that aromatic hydrocarbons, which were excluded by the original specifications for aviation spirit, were in fact beneficial. These researches received a great stimulus by the remarkable discovery of Midgley and Boyd that the presence of lead tetraethyl in minute amounts was able to stop detonation. Since then an immense amount of scientific work has been done on this single phase of oil technology, with the result on the one hand that our knowledge of the processes of combustion at high temperatures and pressures has been greatly enlarged, and on the other that the refiner has been able steadily to meet the ever-increasing demands of the engine designer for fuel of the highest quality. The natural gas from petroleum wells is now stripped of its light hydrocarbons which have a high anti-knock value. Other hydrocarbon constituents of the gas may be dehydrogenated to olefines which in turn are polymerized by heat, with or without the aid of catalysts, to form non-detonating hydrocarbons. Iso-octane, the standard of anti-knock value, is synthesized on the large scale from iso-butene. Ten years ago the average compression ratio of motor-car engines was 4 to 1; that it is now 6 to 1, with obvious improvement in performance and efficiency, is due fundamentally to the work of the chemist and chemical engineer.

The compression-ignition engine now threatens to supplant the more familiar petrol engine altogether as the prime mover for heavy road traction. Here again the refining industry has been called upon to provide an appropriate fuel and to meet demands for quality which required a study of chemical characteristics, and of flame propagation under the most diverse conditions. And as a by-product of its main activities the industry is rapidly growing in importance as a source of intermediates for the chemical manufacturing industry.

There have been equally striking advances in recent years in the methods employed for locating new sources of supply. Fifteen years ago it was realized that the known reservoirs were insufficient to meet the growing demand for many years, and fears were expressed that the supply of mineral oil would soon be exhausted. The annual consumption is now double what it was then, and yet anxiety for the future is no longer acute. This is due on the one hand to the development of methods of exploration which have made possible the exploitation of oil-pools at great depths, and on the other to better control of production. The life of an oil-pool consists normally of a short period of rapidly expanding production followed by a long period of steady decline. Waste was the proverbial accompaniment of all the early oilfield producing practice. The spectacular gushers with their associated loss of oil and gas were by no means the most serious instances of such waste, for there can be little doubt that the lack of control of the reservoir resulted in a very poor recovery of oil. This was suspected by all thoughtful oil operators, but could not be properly assessed until the reservoirs were scientifically examined. It is now agreed that the percentage of oil recovery is at a very unsatisfactory level, and new methods of production are rapidly replacing the older. These involve the conservation of the reservoir gas and its efficient utilization in the process of oil recovery, the recirculation of gas in the reservoir or the introduction of water-flush to drive the oil to the wells, and the return of unmarketable material to the pool. The present tendency is to attempt to introduce a uniform plan of oil production in each oil-pool.

Oil-pools are much more haphazard in their occurrence than coalfields, and their discovery has become increasingly difficult and expensive as the shallower and more obvious areas have been exhausted. Each new region of petroleum exploration presents its own particular problems with which the oil geologist must contend before drilling for new pools can be properly directed. The earlier conception of the simple anticlinal occurrence fits only a modicum of the structural accumulations, and a whole series of favourable and unfavourable conditions for oil accumulation are now recognized. Thus the modern technique of oil discovery is concerned not merely with the geological structure, but with the whole geological history of an area, and it is only by such studies that the inevitable increase in the cost of exploratory drilling due to the greater depth of exploration has been offset by a greater measure of certainty in the search. The need to elucidate geological structures with greater accuracy and to deal with the areas of inadequate geological exposure has led to the adoption of various methods of geophysical exploration. Among the more successful of these in oilfield practice are the Gravimetric and Seismic Surveys. The former, by the development of exceedingly sensitive instruments, is able to detect minute local changes in the horizontal and vertical components of gravity and thus to reveal the variations in rock density underground. The latter method depends on the artificial production of seismic waves, and where the conditions are favourable, is capable of determining the geological structure with a high degree of accuracy. The adoption and improvement of such methods has extended the areas which can be explored successfully, and has led to the discovery of many new oil-pools. The development of electrical coring has been an invaluable aid both in exploratory drilling and in the normal exploitation of oilfields. Its ability to detect the differences between oil and water sands underground has led to a great increase in the efficiency of oil production.

As the shallower fields have become exhausted the average depth of drilling has steadily increased, and exploratory wells have now attained a limit of 12,800 feet. Even this extreme depth is not, perhaps, so remarkable as the fact that economic producing wells of depths ranging from 10,000 to 11,000 feet are now regarded as normal in some oilfields. Drilling to these depths can be done speedily, economically, and with complete control, in spite of the difficulties connected with the increase in rock pressures. Most of the advances in drilling technique have occurred during the last decade and are associated with the improvement of the rotary method of drilling. Initially only suitable for soft strata, it has been adapted for practically all formations by the introduction of new steels and hard cutting alloys into the design of the drilling bits. The problem of high rock pressures has been overcome by the careful physical and chemical control of the mud-flush, whilst the exclusion of extraneous water-bodies has been dealt with by the use of special cements which will set under abnormal conditions. The tendency of deep wells to deviate from the vertical has involved the introduction of careful control of every phase of the drilling operation, and it is only by the adoption of precise methods in the place of the older haphazard conditions that the present success has been attained.

Fears of shortage of supply, coupled with the desire to be nationally self-sufficient in times of war, have also intensified research into methods of producing oil from coal and shales, with the result that it has been conclusively shown that the Bergius method of hydrogenating coal under high pressure, and the Fischer method of obtaining hydrocarbons from carbon monoxide and hydrogen in the presence of catalysts, are both technically successful on the large scale; and although neither process can compete,

under normal economic conditions, with the production of oil from natural sources, yet they may each find a limited utility for special purposes. In any case they provide a welcome insurance for the future, should natural sources fail for unforeseen reasons, and the knowledge and technical skill which has been gained in the course of their development has already been applied with success in other directions.

Whatever phase of oil technology is examined one finds the same fascinating record of scientific and technical progress. During the last few years there have been introduced entirely new methods for the production of lubricating oils, on the supply and quality of which the machinery of the world depends. Practically the whole of the world's supply of lubricants comes from mineral oil. Lubricants derived from some vegetable oils are high in quality, but the amount available is relatively small. In spite of intensive scientific research much remains to be discovered about the essential nature of a lubricant; no laboratory tests have yet been devised which can be completely relied on to give a quantitative measure of lubricating properties. It is known now, however, that certain types of chemical compounds have specially good properties, and that certain mixtures are beneficial; and it is on the basis of this knowledge, and of an accumulation of practical experience, that modern methods for refining lubricating oils are based. A great variety of solvents, such as nitrobenzene, dichlorodiethyl ether, phenol, cresols, and furfural, are now used in practice to extract from certain petroleum distillates the undesirable constituents and to produce a refined lubricating oil of suitable viscosity possessing a relatively low temperature coefficient of viscosity and an enhanced stability towards heat and oxidation.

Crude oil can now be transported cheaply in pipelines over very long distances; the recently completed line in Iraq from Mosul to the Mediterranean is over 1,000 miles long, and was built up entirely of welded sections. The natural gas associated with oil, which may be an appreciable proportion by weight of the crude oil produced, and which was formerly entirely wasted, is now either largely conserved in the reservoir by better control of production, or, as in the United States, is transported through thousands of miles of pipe for use as a domestic and industrial fuel. Propane and butane, which occur in large quantities in natural gas, are separated and sold in bottles in considerable quantities as a portable gaseous fuel. In 1936 the equivalent of 100,000,000 gallons of petrol was sold in the form of bottled gas in the United States. Petroleum technology is indeed unique in that it is concerned with all operations from the discovery and winning of oil to the delivery of refined products to the retailer, and even to the consumer.

The records of all these and many other recent advances in the science and technology of petroleum are scattered in innumerable journals and in the archives of industrial companies. The purpose of the present work is to provide a balanced and comprehensive treatise that shall be critical in treatment and embrace every aspect of the prospecting, production, refining, and transport of mineral oil and gas. The Editors realize that inevitably a certain amount of overlapping has occurred, but they have endeavoured, within the limits and scope of the work, to allow each Contributor freedom to develop his own treatment of his special subject.

They are very grateful to the many Contributors who have taken so much trouble over the preparation of their articles, and have shown so much forbearance in accomodating their contributions to the requirements of a large collaborative work. The Associate Editors have given invaluable advice and assistance in the planning and preparation. Besides thanking collectively 316 Contributors and 24 Associate Editors, they also

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The Editors and the Publisher deeply deplore the death of four contributors who have passed away since their articles were written. These are C. A. Andrews, Paul de Chambrier, S. G. S. Panisset, and Conrad Schlumberger.

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Finally, the Editors wish to record their indebtedness to Mr. J. G. Crowther of the Oxford University Press for all the help they have received from him during the course of their work.

A. E. DUNSTAN
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PART I

ORIGIN AND PRODUCTION OF CRUDE PETROLEUM

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SECTION 1
NOMENCLATURE

NOMENCLATURE OF CRUDE OIL AND ITS PRODUCTS

By Ing. ROBERT SCHWARZ
Vienna

THE industry of the production of crude oil and the distillation of mineral-oil products which is spread over the whole world naturally created different definitions for the various products according to their historical development whereby in some countries the same terms are used for different products.

The uncertainty in the definition of the various terms used in the oil literature, as well as the large number of them, often led to serious mistakes. Many national and international committees and petroleum congresses have tried in vain to stipulate unique terms. Considering the historical development of some expressions and the American attempts at standardization by the American Society for Testing Materials, the German nomenclatures suggested by Professor Dr. von Höfer, the preliminary resolutions of the International Tariff Union, and the different customs declarations, a table has been made out with the endeavour to include in it all the present common terms used in the various countries in science and trade. To be sure in each case which product may be concerned, it must be known with certainty the province and the country from which the product comes. In the scientific literature on petroleum, however, the accuracy of the nomenclature has been improved in the last few years; but in the commercial language, used in the mineral-oil trade, many wrong and inadequate terms for the various products of the industry still exist.

To characterize the present immense confusion, it will be sufficient to indicate only a few typical examples of this industry both with regard to production as well as to distillation and trade.

The raw material, viz. the crude oil, is known in the United States as 'Crude Oil' or 'Petroleum'. In general only the word 'crude' will be added to the names of the localities where the crude oils are produced, so, for instance, 'Pennsylvania Crude', 'Texas Crude', 'Mexican Crude'.

In Russia for crude oil the term 'Neft' is generally in use, and in Roumania sometimes the old term 'Pacura'.

The development of internal combustion engines has increased the demand for light products, which are known in France as 'Essences', in America as 'Gasoline', and in Germany as 'Benzin'.

In America the motor fuels, made from the direct distillation of crude petroleum, are called 'Straight-run Gasoline', whereas others are known as 'Cracked Gasoline', also 'Navy Gasoline' or 'Artificial Gasoline'. Motor fuels from natural gas seldom have trade names, and never with regard to the export trade, because these motor spirits, produced generally from wet or dry gas, are generally used as blending materials for cracked gasolines. The mixture consists of natural gasoline or straight-run gasoline.

In the mineral oil trade we find many terms which are not clearly defined. So, for instance, 'Aviation Gasoline', 'Motor Gasoline', 'Mineral Spirits', 'Benzinum Purificatum' (for pharmaceutical purposes), and even expressions like 'Regular Gasoline', 'Aero Gasoline', 'Export Gasoline', 'Domestic Gasoline', &c.

For kerosine we find terms like: 'Water-white Kerosine', '300 Mineral Seal Oil', 'Signal Oil', 'Gas Oils for Diesel', 'Bunker Oil B', 'Bunker Oil A', 'Straw Oil'. To give the rather endless list of names of lubricating oils, paraffin waxes, petroleum jellies, goudrones, asphalts, bitumens, is quite impossible.

The oldest term known for liquid bitumen—in Germany called 'Erdöl' or 'Petroleum', 'Steinöl', 'Bergöl', 'Bergbalsam', especially 'Quirinusöl' (Tegernsee)—is 'Naphtha' or more correctly 'Nafta'.

In the following list some of the oldest terms for crude petroleum in the various countries are given:

- In England: 'Naphtha';
- in France: 'Naphte', 'Bitume liquide', 'Huile de naphte';
- in the Slav countries: 'Ropianka';
- in Roumania: 'Petrol', 'Păcură', 'Percureli';
- in Spain: 'Aceite de montana';
- in Argentine: 'Brea al quitron';
- in Tscherkessia: 'Kuda';
- in Japan: 'Sekinoyu', 'Kusodsu' (if water white), 'Sekischitza';
- in China: 'Shy-yu';
- in Burma: 'Yenan'.

The more viscous, tar to pitch-like natural bitumens have corresponding names like: 'Erdteer', 'Bergteer', 'Erdpech', 'Bergpech'. Dioscorides called them 'Pittolium' and 'Pittasphaltos', and Pliny 'Pissasphaltus', also 'Maltha' (soft paraffin wax). Some foreign indications run as follows:

- in English: 'Mineral Tar', 'Mineral Pitch';
- in French: 'Bitume visqueux', 'Bitume glutineux', 'Poix minéral', 'Graisse minérale';
- in Spanish: 'Brea'.

Of special importance appear the divergencies of the terms for the same product as used in the various countries. So, for instance, the English (American) word 'Petroleum' means 'Crude Oil', whereas in Germany only 'Rohöl' or 'Erdöl roh' and 'Naphta roh' respectively are used for this product. In the German-speaking countries the term 'Petroleum' is used only for the product which corresponds with the English 'Kerosine' ('Kerosene'), 'Paraffin Oil', and 'Paraffin'. In French the term for 'Crude Oil' is 'Huile brute' or 'Pétrole brut'.

This is rather one of the most characteristic examples for the variety of products of the same name in the various countries.

The English term 'Petrol' or 'Motor Spirit', and in America the term 'Gasoline' or more popularly 'Gas', is equal to the German definition for 'Benzin' (Motorbenzin) which in French is called 'Essence'.

'White Spirit', or 'Solvent Naphtha', called in America for short 'Naphtha', is equal to the German definition 'Lösungsbenzin' or 'Testbenzin'.

Comparatively little confusion exists for the term 'Gas Oil' and 'Fuel Oil'. The term 'Gas Oil' is used in England, America, and France ('Huile solaire'), and even in Russia.

The German expression 'Gasöl' has with regard to the pronunciation nearly the same sound.

The term 'Fuel Oil' (Residue) is nearly equal to the French word 'Residus'.

A special term is 'Ozokerit' which is called in Germany 'Bergwachs', on the Caspian Sea 'Naphthgil' or 'Neftgil', in America 'Gumbed', in France 'Cire fossile' or 'minérale'.

'Asphalt'—known also as black 'Erdharz' (black earth resin), 'Grubenharz' (pit resin)—is *already* mentioned by Herodotus, Aristotle, Strabo, Dioscorides, Pliny, and many others. Dioscorides, chapter 101, says: 'A certain substance, a filtrate of Babylonian asphalt, is called Naphtha of white colour; it can be also dark in colour. It is very inflammable.' The Bible often refers to it. In the following there are some older foreign terms for asphalt:

in English: 'Glance pitch';
in French: 'Bitume compact';
in the Slav language: 'Smola';
in the Hebrew language: 'Hemar' and 'Kofer';
in the old Arabian language: 'Chumal';
in the new Arabian language: 'Elhumar';
in the Assyrian language: 'Kupru', 'Amaru', 'Idulu';
in the Sumerian, that is, the Old-Babylonian language: 'Mur', 'Aschit';
in the old Syrian language: 'Abu th-thâbun (father of soap)';
in the Japanese language: 'Dorekioei', 'Teirekisa'.

'Kir', 'Kar', 'Katrau', 'Katirau' means an earth-paraffin-like, soily asphalt, found on the peninsula Apscheron near Baku.

In the Persian language:

'Maidan-i-Naphtun' or 'Maidan-i-Naphtek' means Oil Field;
'Naphte Sefid' is equal to White Kerosine;
'Sar-i-Naphtek' is equal to Oil Well.

The word 'Petroleum' comes from 'Petrae' (rock or stone) and 'Oleum' (oil), literally, therefore, stone oil. The word 'Kerosine' is derived from 'Ker', which in the Greek language means 'Wax', and the Latin 'Cerum'. 'Naphta', in Russian 'Neft', has been used in Galicia and Russia for crude oil. In America the word 'Naphtha' was used for heavy gasoline.

For motor spirit the most fantastic names were common, such as: 'Canadol', 'Rhigolen', 'Hydrier'; 'Gasolin' for light motor spirits, and 'Petroleumäther' (Kerosine-Ether), but 'Ligroin', 'Benzin', 'Naphtha' for heavy spirits. As time went on the trade names changed for the different products. 'Kerosene', at first introduced on the market by the Kerosene Oil Company, was substituted later on by illuminating oil made from crude oil, which first came to Europe in 1862 under the name 'Pittoel'. 'Kentucky Kerosine' was sold as 'American Medicinal Oil'. In England, for a long time, the American kerosine was considered as American paraffin oil in contradistinction to the kerosine produced from Scotch shale oil. The German term 'Petroleum' for illuminating oil does not correspond with the English definition, where the term 'Petrol' is used for motor fuels, nor with the American definition, where the term 'Petroleum' (Kerosine) is used for crude oil. The definition 'Keroselen' was used for paraffin oil, rectified stone oil, and photogen. On the other hand, the term 'Keroselen' was synonymous for a product which was called in Germany 'Petroläther'. The definition for heavy products is not a unique one. Solar oils were derived originally from brown coal tar and shale oil respectively. Later on, heavy kerosine was called in Russia solar oil like the refined intermediate fraction derived from kerosine.

With regard to the term 'Kerosene' the following may be stated. The English pronunciation of the English term 'Kerosene' is equal to the German pronunciation of the German term spelled 'Kerosin'. According to the suggestions of the Bureau of Standards the correct spelling of the English term is 'Kerosine'. In French 'Kerosine' is called 'Essence', also 'Essence à Pétrole' or 'Pétrole lampant'.

Confusion exists in regard to the nomenclature for asphalts, bitumens, and pitches. This depends on the classification and definition respectively, which conventional or scientific opinion is prepared to establish for mineral oil. At any rate, only the products derived from crude oil are to be termed 'Bitumen'.

The American Society for Testing Materials has published tentative definitions under A.S.T.M. Designation D. 288–35 T (cf. *Nomenclature of Petroleum Products—Nash and Hall*), while the Deutscher Normenausschuss (German Committee for Standardization), under DIN E 6511 and 6512, has drafted a list of standardized terms (in German) of the various mineral-oil products. A draft nomenclature of a 'Proposed Dictionary of Terms for the Petroleum Industry—ISA. 28' has been tentatively submitted for criticism by the International Standardization Association.

The following table (p. 6) includes comparative terms for the Nomenclature of Petroleum and Petroleum Products in various countries.

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NOMENCLATURE (SYNONYMS) FOR OIL PRODUCTS IN VARIOUS COUNTRIES

England	*U.S.A.*	*Germany*	*France*	*Italy*	*Spanish America*	*Roumania*	*Hungary*	*China*	*Japan*
Natural gas	Natural gas	Erdgas	Gaz naturel	Gas minerali	Gas natural	Gaz methan	Foldgáz	Tienyuan-Gas	Tennengas
Petroleum Crude oil	Crude oil Petroleum	Erdöl Rohöl	Pétrole brut Huile brute	Petrolio Olio greggio	Petróleo bruto Petroleo crudo	Titei	Nyers ás- ványolaj kőolaj	Sche Yu	Gen-Yu
Motor spirit Petrol	Gasoline Naphtha	Benzin	Essence Benzine	Benzina	Gasolina Nafta	Benzină	Benzin	Tschi Yu	Kihatsu-Yu Benzen
Kerosine Paraffin (Paraffin oil)	Kerosine	Petroleum Leuchtöl	Pétrole (lampant) Lampant	Petrolina Olio illumi- nante	Petróleo Kerosene	Gaz, Petroleu Lampant	Világító kőolaj Petroleum	Mei Yu	Seki-Yu
Solar oil Gas oil	Gas oil	Gasol Solarol	Huile solaire	Olio di gas	Aceite solar Gas oil	Motorină	Gázolaj	Wha Sze Yu	Gas-Yu
Lubricants (various)	Lubricants (various)	Schmieröl	Huiles de graissage Lubrifiants	Olio lubrifi- cante	Lubricantes (lubrificantes)	Uleiu mineral	Kenőolaj	Dsen Hua Yu	Junkatsu- Yu
Fuel oil Residue	Fuel oil Residue	Heizöl	Brai de Pétrole Résidus	Olio com- bustibile Olio focolai	Fuel oil Petróleo com- bustible	Păcură Reziduu	Fűtőolaj	Mei Dien Yu	Nenryo-Yu
Paraffin wax	Paraffin wax	Paraffin	Paraffine	Paraffina	Parafina	Parafină	Paraffin	Na	Paraffin
Asphalt Bitumen	Asphalt Asphaltic- Bitumen	Asphalt Bitumen	Asphalte Bitume	Asfalto Bitume	Asfalto Bitumen	Smoală Asfalt	Ásványolaj- asphalt Szurok	Aszepha	Asphalt
Petroleum jelly (Vaseline)	Vaseline	Vaseline	Vaseline	Vasellina	Vaselina	Vaselină	Vaselin	Fan Sze Lin	Vaselin

Austria	*Poland*	*Czecho- slovakia*	*Russia*	*Jugoslavia*	*Bulgaria*	*Denmark*	*Norway*	*Sweden*	*Holland*	*Turkey*
Erdgas	Gaz ziemny	Zemní plyn	натуральный газ Gaz	Zemni plin	Zemen gaz	Jordgas	Jordgas	Jordgas	Aardgas	Metan
Erdöl Rohöl	Ropa	Surový olej Zemní olej (nafta)	нефть Neft	Sirovo Ulje	Surov petrol Zemno maslo	Raaolie	Raa- petroleum	Bergolia nativa Mineral- oljor	Aardolie Ruwe olie	Naft, Ham Petrol
Benzin	Benzyna	Benzin	бензин Benzin	Benzin	Benzin	Benzin	Benzin	Bensin	Benzine	Benzin
Petroleum Leuchtöl	Nafta	Petrolej	керосин Kerosin	Petrolej (Gas)	Gaz Petrol	Petroleum	Petroleum Lysolje	Lysolja Fotogen	Lampolie Petroleum Kerosine	Gazyaghi
Gasöl Solaröl	Olej gazowy	Plynový olej Solarový olej	соляровое масло Solja- rowoe maslo	Plinsko Ulje	Gasiol Naft	Solarolie	Solarolje	Solarolja	Gasolie	Gazolin
Schmieröl	Olej maszynowy	Strojní olej	смазочное масло Sma- zoch- noe maslo	Mazivo Ulje	Smazot- chno maslo	Smöreolie	Smöreolje	Smörjolja	Smeerolie	Makina- yaghi
Heizöl	Maź opa- łowa	Zbytek Mazut	мазут Mazut, остатки Ostatki	Ulje za loženje	Petrolen katran	Brænd- selsolie	Brænd- selsolje	Brännolja	Stookolie	Teshinyaghi Mazut
Paraffin	Parafina	Parafin	парафин Parafin	Parafin	Parafin	Parafin	Parafin	Paraffin	Paraffine	Parafin
Asphalt Asphalt- bitumen	Asfalt Bitumen	Asfalt Bitumen	асфальт Asfalt Bitumy	Asfalt Bitumen	Asphalt	Asphalt Bitumen	Asfalt Bitumen	Asfalt Bitumen	Asphalt Bitumen	Asfalt
Vaseline	Wazelina	Vaselin	вазелина Vazelina	Vaselin	Vaselin	Vaseline	Vaselin	Vaselin	Vaseline	Vazelin

THE NOMENCLATURE OF PETROLEUM PRODUCTS

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THE nomenclature of petroleum and petroleum products is of an extensive and diverse character. In common with that of other industries, collaterally developed in more than one country, it suffers from a certain lack of uniformity and precision. The adoption of a uniform terminology, particularly in the English-speaking countries, is the subject of work in progress by the Institution of Petroleum Technologists in Great Britain, the American Society for Testing Materials in the United States, and similar bodies in other countries. A short list of tentative definitions of terms relating to petroleum has been issued by the American Society for Testing Materials and published under Designation D. 288–36T in *A.S.T.M. Standards on Petroleum Products and Lubricants*, 1936. Definitions for the following terms are included:

Crude Petroleum.	Oil Shale.
Crude Shale Oil.	Petroleum Grease.
End-point.	Petroleum Naphtha.
Engine Distillate.	Petroleum Spirits.
Fuel Oil.	Topped Crude Petroleum.
Gas Oil.	Tops.
Gasoline.	Weathered Crude Petroleum.
Kerosine.	

In the following pages is given a list of definitions for the more common terms relating to petroleum and its products, which may be encountered in the technical literature dealing with refining, testing, and marketing. Included in this are the definitions for petroleum products tentatively adopted by the American Society for Testing Materials.

The nomenclature of the bitumens and asphalts, and the nomenclature of crude oil and mineral oil products in different countries, are dealt with in separate contributions and are not included herein.

Free use has been made of many authorities in compiling these definitions, to whom acknowledgement is made.

ABSORPTION GASOLINE. Natural gasoline made by the oil absorption process.

ABSORPTION OIL, STRIPPING OIL, SCRUBBING OIL, WASH OIL. An oil used in the absorption process for absorbing volatile hydrocarbon oil vapours from a gas, exemplified in the recovery of gasoline from natural (casing-head) gas, and of benzole from coke-oven gas. The oil should have an initial boiling-point considerably higher than the final boiling-point of the absorbed spirit.

ACID SLUDGE, ACID TAR. The sludge produced during the chemical refining of hydrocarbon oils with sulphuric acid. It contains free sulphuric acid, hydrocarbon material, and complex organic derivatives of sulphur acids, and may vary from a mobile tar (gasoline refining) to a viscous pitch-like material (lubricating-oil refining).

AIR-BLOWN ASPHALT. *See* Blown Asphalt.

ASPHALT. In England the term asphalt is applied to natural or mechanical mixtures in which asphaltic bitumen is associated with inert mineral matter, and should be qualified by another term indicating the origin of the product.

In the United States the following definition is adopted: Black to dark brown solid or semi-solid materials which gradually liquefy when heated, in which the predominating constituents are bitumens, all of which occur in the solid or semi-solid form in nature or are obtained by refining petroleum, or which are combinations of the bitumens mentioned with each other or with petroleum or derivatives thereof. (A.S.T.M. Designation D. 8–33.)

ASPHALT-BASE CRUDE PETROLEUM. *See* Base of Crude Petroleum.

ASPHALTIC BITUMEN. Natural or naturally occurring bitumen, or bitumen prepared from natural hydrocarbons by distillation or oxidation or cracking; solid or viscous, containing a low percentage of volatile products; possessing characteristic agglomerating properties, and substantially soluble in carbon disulphide.

AVIATION GASOLINE, AVIATION SPIRIT. A special grade of gasoline suitable for use in aeroplane engines. A product of high volatility, knock rating, and degree of refining.

BASE OF CRUDE PETROLEUM. The 'base' of a crude petroleum is descriptive of the chemical nature of its main constituents. A petroleum may be described as paraffin base, asphalt base, or mixed base (intermediate base), according as paraffin wax, asphalt, or both paraffin wax and asphalt are present in the residue after distillation of the lighter components. Typical representatives of these three classes are Pennsylvanian, Mexican, and Mid-Continent petroleums respectively. The term 'naphthene base', sometimes used synonymously for 'asphalt base', is preferably retained for such crude petroleums as Russian, of non-paraffinic character, but containing a relatively low proportion of asphalt (the term 'asphalt' referring to the U.S. definition). A more precise system of nomenclature and method of differentiation is that of the United States Bureau of Mines.

BENZINE. An indefinite term, the use of which is to be avoided, which is loosely applied to any refined, volatile, hydrocarbon distillate, especially that obtained from the fractional distillation of petroleum. To be distinguished from the aromatic hydrocarbon *Benzene*.

BENZINUM PURIFICATUM. The 'Purified Petroleum Benzine' of the United States Pharmacopoeia. A purified distillate from American petroleum, of sp. gr. 0·634–0·660 at 25° C. and distilling completely between 35 and 80° C.

BENZOLE, BENZOL. Commercial name applied to benzene, not necessarily pure, and to liquid distillates containing a high proportion of benzene and its homologues (toluene and xylene). The term '50/90's Benzole' refers to a product of which 50% distils up to 100° C. and 90% to 120° C., while '90's Benzole' ('90 per cent. benzole') yields 90% between 80 and 100° C. See Motor Benzole.

BITUMENS. Mixtures of hydrocarbons of natural or pyrogenous origin, or combinations of both frequently accompanied by their non-metallic derivatives, which may be gaseous, liquid, semi-solid or solid, and which are completely soluble in carbon disulphide. (A.S.T.M. Designation D. 8–33.)

BITUMINOUS EMULSION. A liquid product for application to road surfaces, in which a substantial amount of

asphaltic bitumen or other bituminous road-binder is suspended in finely divided condition in an aqueous medium by means of one or more suitable emulsifying agents.

BLACK OIL. A term generally applied to any dark-coloured lubricating oil of relatively high asphalt content, suitable for rough uses or heavy lubrication.

It has been used in Great Britain to designate such petroleum products as gas oil, diesel oil, and fuel oil, to the exclusion of gasoline, white spirit, kerosine, and lubricating oils, but its use in this connexion is to be deprecated.

BLAU GAS. A mixture of gaseous and volatile hydrocarbons with hydrogen, used for fuel purposes and prepared by the thermal decomposition (high-temperature cracking) of hydrocarbon oils. The gas may be compressed and liquefied before use, in which case hydrogen and other uncondensable gases will be absent.

BLOWN ASPHALT. Asphalt (U.S. definitions), or Asphaltic bitumen, obtained by blowing air through petroleum residua, or natural bituminous substances, heated during the blowing process.

BLOWN OILS. Products obtained by the action of air upon oils at an elevated temperature. The process is carried out to change the physical characteristics, e.g. to increase the viscosity.

BLUE OIL. Term frequently applied, in Great Britain, to *Pressed Distillate*.

BOTTOMS. The residue left in a still after distillation; the undistilled liquid and condensate drawn off from the bottom of a fractionating tower, dephlegmating column, or similar apparatus.

BOTTOM SEDIMENTS, 'B.S.'. The sediment which settles out from a crude petroleum or fuel oil during storage, usually an emulsified mixture of oil and water with wax, asphalt, mud, and other extraneous material.

BRIGHT STOCK. High-viscosity lubricating oils, prepared from cylinder stock by dewaxing and earth filtration. The term is also applied to viscous distillate stocks from certain mixed-base and naphthene-base crudes. Bright stocks are used chiefly as a blending medium in the production of lubricating oils for automobile and aeroplane engines.

BURNING OIL. Term commonly applied to kerosine and similar oils suitable for burning in lamps and stoves.

BUTANE. Generic name for the paraffin hydrocarbons of formula C_4H_{10}, *n*-butane (b.p. $+0{\cdot}6°$ C.) and *iso*-butane (b.p. $-10{\cdot}2°$ C.). The term is applied to commercial liquefied (fuel) gases, containing chiefly butane and/or the unsaturated *butenes*, and separated from natural and refinery gases.

CABLE OIL. An oil used for the impregnation of electric transmission cables.

CARBON BLACK. A product, essentially very finely divided carbon, prepared by the regulated, incomplete combustion of hydrocarbon gases, or of inflammable oils, or by the thermal or electrical decomposition of hydrocarbon gases.

CASING-HEAD GAS. Name applied to the gas which issues from the casing-head of oil-wells. *See* Natural Gas.

CASING-HEAD GASOLINE. *See* Natural Gasoline.

CERESINE. A white or yellow, opaque, wax-like solid, obtained from *Ozokerite* by suitable refining treatment. Ceresine is an amorphous mixture of solid hydrocarbons, related to paraffin wax, but usually of higher melting-point (70–80° C. e.g.).

CLEANERS' NAPHTHA, CLEANERS' SOLVENT. A refined petroleum fraction used in the dry cleaning of clothing, with a boiling range which normally lies between 100 and 200° C.

COAL OIL. Crude oil obtained by the distillation of coal. The term has, in the past, been incorrectly applied to kerosine.

COMPOUNDED OIL. A mineral oil compounded or blended with animal, vegetable, or similar oils.

CRACKED DISTILLATE. A distillate obtained from the cracking process, or from a distillation in which some cracking has occurred.

CRACKED GASOLINE, CRACKED NAPHTHA. Gasoline or naphtha obtained by the cracking process—a process involving molecular decomposition by which low-boiling products are obtained from higher boiling materials through thermal treatment.

CRACKING GAS, CRACKER GAS. Gas obtained as a by-product in the cracking process, and characterized by the presence of unsaturated hydrocarbons.

CRACKING STOCK. Any oil or similar product which is utilized as starting material for the cracking process.

CRUDE NAPHTHA. Naphtha in an unrefined state.

CRUDE OIL, CRUDE. A synonym for *Crude Petroleum*. Descriptive of any oil in an unrefined state.

CRUDE PETROLEUM. A synonym for *Petroleum* as obtained in the natural state, denoting the absence of any refining other than the possible removal of gas, water, and other extraneous material. *See* Petroleum.

The American Society for Testing Materials define crude petroleum as: A naturally occurring mixture, consisting predominantly of hydrocarbons, and/or sulphur, nitrogen, and/or oxygen derivatives of hydrocarbons, which is removed from the earth in liquid state or is capable of being so removed.

Note. Crude petroleum is commonly accompanied by varying quantities of extraneous substances such as water, inorganic matter, and gas. The removal of such extraneous substances alone does not change the status of the mixture as crude petroleum. If such removal appreciably affects the composition of the oil mixture, then the resulting product is no longer crude petroleum. (A.S.T.M. Designation D. 288-36T.)

CRUDE SHALE OIL. The oil obtained as a distillate by the destructive distillation of oil-shale. (A.S.T.M. Designation D. 288-36T.)

CUT. Term applied to any fraction obtained by distillation or other selective separatory process.

CUT-BACK PRODUCT. A residuum which has been 'cut back', 'fluxed', or diluted by blending with a distillate fraction. A heavy oil blended with a lighter oil to bring it to a desired specification. *See* Flux Oil.

CUTTING OIL. An oil used for the lubrication and cooling of metal cutting tools. Cutting oils may comprise straight or compounded lubricating oils, used as such, or soluble oils used in the form of an emulsion with water.

CYLINDER STOCK. Viscous residual oils obtained by the distillation of certain crude petroleums of low asphalt content, and used for steam-cylinder lubricating oils, and in the preparation of *Bright Stock*.

DEBUTANIZED GASOLINE. *See* Stabilized Gasoline.

DIESEL ENGINE OIL. A lubricating oil used for the lubrication of Diesel engines.

DIESEL OIL, DIESEL FUEL. A special grade of fuel oil for Diesel engines.

DRY GAS. A gas containing a relatively low proportion of

readily condensable constituents, e.g. a natural gas of low recoverable gasoline content. *See* Natural Gas.

DRYING OIL. An oil subject to ready oxidation which, on exposure in thin layers to the atmosphere, is converted to a relatively hard elastic film.

DUST-LAYING OILS. *See* Road Oils.

EDELEANU EXTRACT. That portion of an oil extracted by liquid sulphur dioxide in the Edeleanu refining process. Term usually refers to that from the refining of kerosines, comprising a highly aromatic oil, frequently of high sulphur content.

EMULSIFIABLE OIL. *See* Soluble Oil.

END-POINT. The highest temperature reading observed on the distillation thermometer during the distillation procedure conducted in accordance with the Standard Method of Test for Distillation of Gasoline, Naphtha, Kerosine, and Similar Petroleum Products (A.S.T.M. Designation D. 86) and the Standard Method of Test for Distillation of Natural Gasoline (A.S.T.M. Designation D. 216) of the American Society for Testing Materials (A.S.T.M. Designation D. 288–36T).

ENGINE DISTILLATE. A refined or unrefined petroleum distillate similar to naphtha, but often of higher distillation range. (A.S.T.M. Designation D. 288–36T.)

ENGINE OIL. Lubricating oil of moderate viscosity suitable for the lubrication of exposed bearings (not cylinder lubrication) of internal-combustion (gas) engines and steam engines.

ETHYL FLUID. A liquid product containing over 50% lead tetraethyl, used by the Ethyl Gasoline Corporation, for blending with motor spirits to improve their anti-knock characteristics.

ETHYL GASOLINE, ETHYLIZED FUEL. A gasoline or motor spirit containing a proportion of *Ethyl Fluid.*

EXTRACT. Term applied, in solvent-refining processes, to that portion of the oil which is dissolved in and removed by the selective solvent used.

FILTERED STOCK. A lubricating stock which has been filtered through fuller's earth or other filtering medium.

FLOTATION OIL. An oil used in the flotation process of concentrating mineral ores.

FLUX, FLUX OIL. (1) A liquid residuum from asphalt-base crude petroleums. (2) An oil for blending with asphaltic or bituminous materials for the purpose of softening or reducing their consistency. *See* Cut-back Product.

'FOOTS' OIL, 'SWEATS'. A mixture of oil and soft paraffin wax which separates during the sweating process, in the production of paraffin wax from slack wax. It is usually returned to the paraffin distillate for re-pressing.

FUEL OIL. A very general term which may be applied to any oil used for the production of power and heat.

In a more restricted sense it is applied to any oil or liquefiable product burned for the generation of heat in a domestic or industrial furnace or firebox, or for the generation of power in a Diesel engine, excluding oils burned in wick burners. Fuel oils in common use fall into one of four classes:

(1) residual fuel oils, which are topped crude oils or viscous residua obtained in refining operations;
(2) distillate fuel oils, which are distillates derived from crude petroleum, coal oil, or other suitable material;
(3) crude petroleums and weathered crude petroleums of relatively low commercial value;
(4) blended fuels, which are mixtures of two or more of the preceding classes.

Under A.S.T.M. Designation D. 288–36T, this definition is further restricted to petroleum products with a closed flash-point above 100° F.

GAS. Term commonly applied to gasoline, in the United States, by the motoring public.

GAS BLACK. A form of carbon black, prepared by the incomplete combustion of hydrocarbon gases.

GAS OIL. A liquid hydrocarbon distillate, generally from petroleum, of viscosity and boiling range intermediate between those of kerosine and lubricating oil. Suitable grades of gas oil are used for absorption oils, for Diesel oils, as cracking stock, and in the manufacture of oil gas by high-temperature cracking. Oils other than gas oil, as defined above, may be, and are, used for the manufacture of gas.

The following tentative definition is accepted by the American Society for Testing Materials: A liquid petroleum distillate having a viscosity intermediate between that of kerosine and lubricating oil. (A.S.T.M. Designation D. 288–36T.)

GASOLINE. Commercial name applied to a refined hydrocarbon distillate, usually restricted to that of petroleum origin, of characteristics suiting it for use as a carburetting fuel in internal-combustion engines. Originally prepared only from the first distillate cut of crude petroleum, gasoline now includes 'natural gasoline' recovered from natural gas, 'polymer gasoline' from the polymerization of hydrocarbon gases, and 'cracked gasoline' from the cracking of heavier oils. Commercially marketed gasolines are usually a blend of two or more of these products, and may in addition contain dopes such as lead tetraethyl, and other fuels such as benzole and alcohol. The boiling range of gasolines varies, but lies usually within the range 30–200° C. (85–390° F.).

The following definition is accepted by the American Society for Testing Materials: A refined petroleum naphtha which by its composition is suitable for use as a carburant in internal-combustion engines. (A.S.T.M. Designation D. 288–36T.) *See* Petrol, Motor Spirit.

GAS SPIRIT. Term applied, particularly in coal carbonization practice, to the mixture of volatile liquid hydrocarbons extracted from a gaseous mixture by the application of compression, absorption, or adsorption processes.

GREASE. *See* Lubricating Grease.

GUM. In the petroleum industry the term is descriptive of resin-like, insoluble deposits formed through the deterioration of petroleum and its products, particularly gasoline. The tendency of a gasoline to deposit gum, either on evaporation or during storage, is a factor of importance in its evaluation, and may be especially pronounced in cracked distillates. 'Existent Gum' or 'Preformed Gum' is the number of milligrams of residue from the evaporation of 100 ml. of a gasoline or motor spirit under specified conditions. 'Potential Gum' refers to the gum which is deposited by a gasoline or motor spirit, during storage, or under accelerated ageing conditions.

HARD PARAFFIN. *See* Paraffinum Durum.

HEAVY ENDS. The relatively high-boiling components of a distillate fraction.

HEAVY OILS. In the Excise Tariff of Great Britain, the term heavy oils refers to hydrocarbon oils other than light oils. *See* Light Oils.

HYDROSOLVENTS. Term applied to synthetic hydrocarbon solvents, of high aromatic content, obtained from petroleum oils by a combination of hydrogenation and cracking at relatively high temperatures and low pressures.

ICHTHYOL. An oily product of high sulphur content, used for pharmaceutical purposes, prepared by the sulphonation of shale oil and subsequent neutralization with ammonia.

ILLUMINATING OIL. An oil suitable for burning as an illuminant. *See* Burning Oil, Kerosine.

INHIBITOR. A substance which, when present in relatively small proportions, will arrest or suppress a chemical reaction. Inhibitors (notably amino and phenolic compounds) are used for suppressing gum formation in motor spirit.

INSULATING OILS, ELECTRICAL INSULATING OILS. Oils used in circuit-breakers, switches, transformers, and other electrical apparatus for the purpose of insulation, or cooling, or both. In general, insulating oils are well-refined petroleum distillates of low volatility, showing particularly high resistance to oxidation and sludging, which possess viscosities ranging from that of *Mineral Seal Oil* to those of light lubricants.

Iso-OCTANE. Commercial name for 2:2:4:trimethylpentane, C_8H_{18}, an iso-paraffin hydrocarbon used as a primary standard in the knock rating of motor fuels. It is prepared from the butylene fraction of cracking gas, by polymerization and hydrogenation.

KEROSINE, KEROSENE. A refined hydrocarbon distillate from petroleum, shale oil, or similar material, which is the intermediate product between gasoline and gas oil, and which normally distils within the range 150–300° C. Kerosines marketed in Great Britain and in the United States are required by legislation to have a closed flash-point not lower than 73° F. in the Abel Tester, and, in general, are oils suitable for use as illuminants when burned in wick lamps. Special kerosines (e.g. Power Kerosines) are also produced for other specific purposes.

The following tentative definition is accepted by the American Society for Testing Materials: A refined petroleum distillate having a flash-point not below 73° F. (23° C.), as determined by the Abel Tester (which is approximately equivalent to 73° F. (23° C.) as determined by the Tag Closed Tester, A.S.T.M. Standard Method D. 56) and suitable for use as an illuminant when burned in a wick lamp.

Note. In the United States of America local ordinances or insurance regulations require flash-points higher than 73° F. (23° C.), Tag Closed Tester. (A.S.T.M. Designation D. 288–36T.)

LAMP OIL. *See* Illuminating Oil, Burning Oil, Kerosine.

LEADED FUEL. A motor fuel containing lead tetraethyl. *See* Ethyl Gasoline.

LEAN GAS. A *Dry Gas*, or one which has been denuded of its more condensable constituents.

LIGHT DISTILLATE. Term applied to relatively low-boiling distillates, such as gasoline and kerosine fractions, usually boiling below 300° C. *See* Naphtha.

LIGHT OILS. In the Excise Tariff of Great Britain, the term light oils refers to hydrocarbon oils of which not less than 50% by volume distils at a temperature not exceeding 185° C., or of which not less than 95% by volume distils at a temperature not exceeding 240° C., or which give off an inflammable vapour at a temperature of less than 22·8° C. (73° F.), when tested in the manner prescribed by the Acts relating to petroleum.

LIGHT PETROLEUM. *See* Petroleum Leve.

LIQUID PARAFFIN. *See* Paraffinum Liquidum.

LIQUID PETROLATUM. *See* Petrolatum Liquidum.

LONG RESIDUUM. A residuum from a paraffin-base or mixed-base crude petroleum, of relatively low flash-point, containing all the lubricating-oil fractions, and frequently lighter fractions, of the original crude.

LONG-TIME BURNING OIL. A particularly high-grade burning oil for illuminating purposes, similar to *Mineral Seal Oil*, and used in signal lamps, &c.

LUBE OIL, LUBE. Abbreviated form of Lubricating Oil, Lubricant.

LUBRICATING GREASE. A solid or semi-solid oily material used for certain classes of lubrication. Petroleum lubricating greases are combinations of petroleum products, generally lubricants, with a soap or mixture of soaps. *See* Petroleum Grease.

LUBRICATING OIL. Any liquid oil used for the purpose of lubrication. Lubricating oils may be animal, vegetable, petroleum, or other products, or mixtures of these. Petroleum lubricating oils may be distillates or residues and may vary in viscosity from very mobile spindle oils to extremely viscous cylinder stocks.

MACHINE OIL, MACHINERY OIL. A lubricating oil suitable for the lubrication of the moving parts of machinery, not subject to extreme conditions of temperature, pressure, or rubbing speed.

MATCH WAX. A paraffin wax of low melting-point, usually 105–115° F., chiefly used for the impregnation of match splints.

MAZOUT. A term sometimes applied to crude petroleum residues after distillation and removal of the more volatile components. (Russian.)

MEDICINAL OIL. *See* Paraffinum Liquidum, Petrolatum Liquidum.

MEDICINAL PARAFFIN. *See* Paraffinum Liquidum.

MIDDLE OIL. A fraction distilling chiefly between 200 and 300° C. The term *Middle Oil Distillate* is sometimes applied in petroleum refining to the fraction known as gas oil.

MINERAL COLZA OIL. *See* Mineral Seal Oil.

MINERAL JELLY. *See* Petrolatum.

MINERAL OIL. Any oil obtained from a mineral source, including the liquid products and distillates from crude petroleum, shale oil, coal tar, &c.

MINERAL SEAL OIL. A refined petroleum distillate intermediate between kerosine and gas oil. *Mineral Colza* oil is a similar product.

MINERAL SPIRITS. *See under* Petroleum Spirits.

MIXED-BASE CRUDE PETROLEUM. *See under* Base of Crude Petroleum.

MONTAN WAX, MONTANIN WAX. A wax obtained by distillation or extraction of lignite.

MOTOR FUEL. Any material suitable for use as a fuel in an internal-combustion engine.

MOTOR SPIRIT. Generic name for volatile liquid fuels suitable for use as carburetting fuels in internal-combustion engines. The term is very general and includes petroleum and shale-oil products, low-temperature coal carbonization spirits, benzole, alcohols, mixtures of these, and other suitable volatile and combustible liquid mixtures, together with anti-detonation dopes such as lead tetraethyl.

The term *Gasoline* is preferred in the United States for motor spirits of predominantly petroleum origin, while in Great Britain the term *Petrol* is commonly accepted.

NAPHTHA. A general term applied to the lower boiling liquid fractions, or the first distillation cut, obtained from petroleum, shale oil, coal tar, and similar sources, and during such refining operations as cracking, poly-

merization, reforming, and stripping. It is usually confined to fractions which distil below 250 to 300° C., and may refer to the crude or refined product. *See* Petroleum Naphtha.

NAPHTHENE-BASE CRUDE PETROLEUM. *See under* Base of Crude Petroleum.

NAPHTHENIC OIL. Term applied to hydrocarbon oils of relatively high carbon/hydrogen ratio and of predominantly cyclic chemical structure, such as are obtained from naphthene- and asphalt-base crude petroleums. *See* Paraffinic Oil.

NATURAL GAS. A gaseous mixture, generally of predominantly hydrocarbon composition (but which may contain carbon dioxide, hydrogen sulphide, nitrogen, helium, &c.), found in nature. It is frequently associated directly with petroleum of which it may then be regarded as the gaseous component, and is a factor of considerable importance in its recovery and conservation. The hydrocarbon constituents of natural gas, chiefly methane, with varying proportions of its chemical homologues ethane, propane, butane, &c., are closely related to, or identical with, those present in petroleum and, in so far as both natural gas and petroleum are capable of existing in the liquid or gaseous state under suitable conditions of temperature and pressure, no strict distinction can therefore be made between them.

Natural gas may be classified as 'wet' or 'dry' according as it contains a relatively large or small proportion of gasoline constituents (propane, butanes, pentanes, &c.) recoverable by suitable means, the figure of 1 gal. of gasoline per 1,000 cu. ft. of gas being commonly accepted as the limiting amount.

NATURAL GASOLINE, CASING-HEAD GASOLINE. A low-boiling liquid petroleum product, consisting of the heavy hydrocarbons extracted from *Natural Gas* by the application of compression, absorption, adsorption, or other processes. Natural gasoline has a Reid vapour pressure of 10–34 lb. per sq. in. at 100° F., and should show 25–85% evaporated at 140° F. and not less than 90% at 275° F. (National Gasoline Association of America). In the unstabilized condition—Wild Gasoline—it contains a relatively high proportion of propane and butanes of high vapour pressure. By stabilization or debutanization the propane and part of the butanes are removed, yielding a stabilized gasoline, of relatively low vapour pressure, suitable for blending purposes.

NEUTRAL OILS, NEUTRALS. Lubricating oils, of low and medium viscosity, from the further treatment of the *Pressed Distillate*, or *Blue Oil*, produced in dewaxing practice. Neutral oils are chiefly used as lubricating-oil stocks for blending purposes.

The term is now commonly used to include any distillate lubricating oil of low or medium viscosity, whether from paraffinic or asphalt-base crudes.

NON-SLUDGING OIL. An oil resistant to the deposition of sludge during service. *See* Electric Insulating Oil.

NON-VISCOUS NEUTRAL OIL. A neutral oil of viscosity lower than 135 sec. Saybolt Universal at 100° F.

NORMAL BENZINE. A highly refined petroleum distillate used in Germany for the estimation of asphaltenes. It is free from unsaturated and aromatic hydrocarbons, has an aniline-point of approximately 60° C., and a boiling range of 65–95° C.

OCTANE. *See Iso*-OCTANE.

OILFIELD EMULSION. Emulsions of crude petroleum and water, with other material, obtained in oilfield production practice.

OIL FUEL. Term restricted to *Fuel Oils* burnt for steam-raising purposes.

OIL GAS. An inflammable gas, containing a high proportion of hydrocarbons, obtained by the destructive thermal decomposition of oils. *See* Blau Gas.

OIL SHALE. A naturally occurring rock, which may be petrographically classed as a shale, and which, upon destructive distillation, will yield an oil resembling crude petroleum.

The following tentative definition is accepted by the American Society for Testing Materials: A compact rock of sedimentary origin, with an ash content of more than 33% and containing organic matter that yields oil when destructively distilled, but not appreciably when extracted with the ordinary solvents for petroleum. (A.S.T.M. Designation D. 288–35T.)

OZOKERITE. A naturally occurring waxy mixture of hydrocarbons, related to petroleum, found in certain parts of eastern Europe, America, &c. *See* Ceresine.

PAINTERS' NAPHTHA. *See* Petroleum Spirits, White Spirit.

PAINT THINNERS. *See* Petroleum Spirits, White Spirit.

PALE OILS. General term applied to any low- or medium-viscosity petroleum lubricating oil of pale colour. Formerly restricted to the light-coloured *Neutral Oils* obtained as distillates from the treatment of pressed distillate or blue oil.

PARAFFIN. (1) Term applied to a member of the paraffin series of hydrocarbons of composition C_nH_{2n+2}.

(2) An alternative name used for paraffin wax. *See* Paraffinum.

(3) Paraffin, Paraffin Oil are names commonly applied by the public in Great Britain to kerosine.

PARAFFIN-BASE CRUDE PETROLEUM. *See under* Base of Crude Petroleum.

PARAFFIN DISTILLATE, WAX OIL. A lubricating-oil distillate fraction containing paraffin wax in a crystalline form, suitable for chilling and filter-pressing.

PARAFFINIC OIL. Term applied to hydrocarbon oils of relatively low carbon/hydrogen ratio and of predominantly open-chain (aliphatic) chemical structure, such as are obtained from paraffin-base crude petroleums. *See* Naphthenic Oil.

PARAFFIN OIL. A distillate lubricating oil from paraffinic or mixed-base crude petroleums.

The term is in common use in Great Britain to designate kerosine.

PARAFFIN SCALE. The residual crude paraffin wax obtained after the process of sweating the *Slack Wax*.

PARAFFIN SLACK WAX, SLACK WAX. The crude soft paraffin wax obtained by chilling and filter-pressing paraffin distillate or wax distillate.

PARAFFINUM. The 'Paraffin' of the United States Pharmacopoeia. A purified paraffin wax obtained from petroleum, of m.p. 50–57° C. and suitable for pharmaceutical purposes.

PARAFFINUM DURUM. The 'Hard Paraffin' of the British Pharmacopoeia. A purified paraffin wax obtained from petroleum or shale oil, of m.p. 50–60° C.

PARAFFINUM LIQUIDUM. The 'Liquid Paraffin' of the British Pharmacopoeia. A highly refined white petroleum oil used for medicinal purposes, of sp. gr. 0·880–0·895 and viscosity not less than 260 sec. Redwood at 37·8° C. (100° F.). 'Paraffinum Liquidum Leve', light liquid paraffin, or spray paraffin, is used as a vehicle for

oil-spraying solutions, and has a viscosity and specific gravity lower than those of liquid paraffin.

PARAFFINUM MOLLE. The 'Soft Paraffin' of the British Pharmacopoeia. A highly refined petrolatum available in two grades, yellow (flavum) and white (album), of melting-point between 38 and 46° C., and suitable for medicinal purposes.

PARAFFIN WAX. A mixture of solid hydrocarbons of the paraffin series, obtained from petroleum, from the distillation of shale, from the low-temperature distillation of coal, and from other sources. In the purified state, paraffin wax is a colourless, more or less translucent mass without taste or odour, crystalline when separating from solution, and slightly greasy to the touch. The melting-point of a paraffin wax may vary widely over a considerable range according to the source and mode of preparation of the wax. That of typical commercial varieties may vary from 40 to 60° C. (105–140° F.).

PEPPER SLUDGE. A fine suspension of acid sludge remaining dispersed in a sulphuric acid treated oil, after the main bulk of the acid sludge has settled out.

PETROL. Term commonly used in Great Britain for *Motor Spirit* or *Gasoline*.

PETROLATUM, PETROLEUM JELLY. A purified semi-solid mixture of hydrocarbons, of paste-like consistency, obtained from petroleum. Petrolatum is a naturally occurring mixture containing soft amorphous paraffin wax with viscous oil, obtained in the dewaxing of residual paraffin-base cylinder stocks.

PETROLATUM. The 'Petrolatum' of the United States Pharmacopoeia. A highly purified product of sp. gr. 0·820–0·865 at 60° C., melting between 38 and 54° C.

PETROLATUM LIQUIDUM. The 'Liquid Petrolatum' of the United States Pharmacopoeia. A highly refined white petroleum oil, known also as liquid paraffin or white mineral oil, used for medicinal and pharmaceutical purposes. Light liquid petrolatum (used for atomization) has a kinematic viscosity of not more than 0·370 at 37·8° C., while heavy liquid petrolatum has a viscosity not less than 0·381.

PETROLEUM. Petroleum, in its widest sense, may be considered to embrace all hydrocarbons, solid, liquid, and gaseous, occurring in nature. It is more precisely defined as a material, occurring naturally in the earth, which is predominantly composed of mixtures of chemical compounds of carbon and hydrogen with or without other non-metallic elements such as sulphur, oxygen, nitrogen, &c. Petroleum may contain, or be composed of, such compounds in the gaseous, liquid, and/or solid state, depending on the nature of these compounds and the existent conditions of temperature and pressure; it may, and frequently does, contain other extraneous material, including non-hydrocarbon gases, water, and earthy matter, in admixture. That portion of petroleum which, under normal conditions, is in the gaseous state, is commonly termed 'Natural Gas' (although the term 'Natural Gas' may not be restricted to this definition), but it should be understood that, in so far as all compounds are capable of existing in the solid, liquid, or gaseous states, depending upon the conditions of temperature and pressure, no strict distinction can rightly be drawn between gaseous, liquid, or solid components of petroleum. *See* Crude Petroleum; Natural Gas; Base of Crude Petroleum.

PETROLEUM ASPHALT. An asphalt (U.S. definition) obtained by suitable treatment from petroleum or its products. The distillation residue from an asphalt-base crude petroleum.

PETROLEUM COKE. The solid carbonaceous material obtained as a residue from the destructive distillation of petroleum, as in cracking and coking distillation practice.

PETROLEUM ETHER. A purified low-boiling petroleum fraction, usually with a boiling range below 120° C. 60–80 petroleum ether refers to a product distilling between 60 and 80° C.

PETROLEUM GREASE. A semi-solid or solid combination of a petroleum product and a soap or a mixture of soaps, with or without fillers, suitable for certain classes of lubrication. (A.S.T.M. Designation D. 288–36T.)

PETROLEUM JELLY. *See* Petrolatum.

PETROLEUM LEVE. The 'Light Petroleum' of the British Pharmaceutical Codex. A refined distillate from the lower boiling fractions of natural petroleum, shale oil, low-temperature tar, or products of hydrogenation of coal or cracking of oils; 95% distils between 40 and 60° C.

PETROLEUM NAPHTHA. A generic term applied to refined, partly refined, or unrefined petroleum products and liquid products of natural gas, not less than 10% of which distils below 464° F. (240° C.) when subjected to distillation in accordance with the standard method of test for distillation of gasoline, naphtha, kerosine, and similar petroleum products (A.S.T.M. Designation D. 86) of the American Society for Testing Materials.

Note. The 'naphthas' used for specific purposes, such as cleaning, manufacture of rubber, manufacture of paints and varnishes, &c., are made to conform to specifications which may require products of considerably greater volatility than that set by the limits of the generic definition.

(Tentative Definition, A.S.T.M. Designation D. 288–36T.)

PETROLEUM SPIRITS, WHITE SPIRITS. A refined petroleum distillate with a minimum flash-point of 70° F. (21° C.), determined by the Tag Closed Tester in accordance with the standard method of test for flash-point of volatile inflammable liquids (A.S.T.M. Designation D. 56) of the American Society for Testing Materials, or by the Abel Tester, with volatility and other properties making it suitable as a thinner and solvent in paints, varnishes, and similar products.

Note. The term 'turpentine substitute', as applied to petroleum spirits, is to be condemned as false and misleading. The term 'Mineral Spirits' is a misnomer, as it includes within its scope not only petroleum products, but other hydrocarbon mixtures such as coal tar distillates. In Great Britain the term 'Petroleum Spirits' is applied to a very light hydrocarbon mixture having a flash-point below 32° F. (0° C.).

(Tentative Definition, A.S.T.M. Designation D. 288–35T.)

PINTSCH GAS. *See* Oil Gas.

PITCH. The solid residue from the distillation of coal tar. The term should not be applied to petroleum products, unless qualified by the prefix 'petroleum'.

POLYMER GASOLINE. Gasoline obtained by the polymerization of gaseous hydrocarbons, by thermal, catalytic, or other means.

POWER KEROSINE. Kerosine of such characteristics suiting it for use as a carburetting fuel in internal-combustion engines. Power kerosines, known also as Tractor Oils and Power Vaporizing Oils, have relatively high overall

volatility and anti-knock rating in comparison with *Burning Oils*.

PRESSED DISTILLATE, BLUE OIL. The oil obtained by chilling and filter-pressing the paraffin distillate or wax distillate, prior to the finishing treatment for the production of *Neutral Oils*.

PRESSURE DISTILLATE. The crude distillate obtained from the cracking process prior to final fractionation and refining.

PROPANE. A gaseous paraffin hydrocarbon of formula C_3H_8 (b.p. $-44{\cdot}5^\circ$ C.), which may be separated from natural and refinery gases; used, in the compressed state, as a fuel gas.

QUENCHING OIL. An oil used for cooling metal components in hardening and tempering operations. Also termed Tempering Oil, Hardening Oil.

RAFFINATE. Term applied, in solvent-refining practice, to that portion of the oil which remains undissolved and is not removed by the selective solvent used.

RECOVERED ACID. Sulphuric acid which has been recovered, for subsequent re-utilization, from the acid sludge produced during the sulphuric acid refining of mineral oils.

RECOVERED OIL. Used lubricating oil which has been recovered and purified for subsequent re-utilization.

RED OIL. General term applied to transparent dark-coloured distillate lubricating oils. Formerly restricted to the darker coloured *Neutral Oils* obtained as residuals in the treatment of *Pressed Distillate* or *Blue Oil*.

REDUCED OIL. An oil from which the more volatile constituents have been removed by distillation.

REFERENCE FUEL. A fuel of accurately standardized characteristics used as a reference standard in the engine-testing of motor fuels, as, for example, in the routine determination of Octane Numbers and Cetane Numbers.

REFINERY GASES. Hydrocarbon gases produced during petroleum-refining operations, such as cracking, distillation, and stabilization.

REFORMED GASOLINE. A gasoline obtained by the reforming process, in which a material of low octane number (a straight-run gasoline for example) is subjected to cracking at relatively high temperatures and pressures to yield a product of substantially similar boiling range but of higher octane number.

RE-RUN OIL. An oil subjected to redistillation.

RESIDUAL ASPHALT. The untreated asphaltic residue from the distillation of an asphalt-base crude petroleum.

RESIDUUM. The residue obtained from the distillation of crude petroleum after gasoline, kerosine, and sometimes heavier distillates have been taken off.

RESINS. The term has been loosely applied to those constituents of an oil extracted by adsorbent earths such as fuller's earth, and which in turn can be extracted from the earth by benzene, chloroform, or similar solvent.

RICH GAS. A gas containing a relatively high proportion of readily condensable constituents. *See* Wet Gas.

ROAD OIL. An oil suitable for applying to earth roads to prevent dust and to consolidate and waterproof the surface.

ROD WAX. A pasty mass, composed chiefly of an emulsion of paraffin wax and oil, collecting about sucker rods and casing when pumping paraffinic crude oil wells.

SCALE WAX. *See* Paraffin Scale.

SHALE OIL. The crude oil obtained by the destructive distillation of oil shale.

SCRUBBING OIL. *See* Absorption Oil.

SLACK WAX. *See* Paraffin Slack Wax.

SLOP WAX FRACTION. A distillate fraction, from a paraffin- or mixed-base crude petroleum, taken off after the wax distillate, to give a residuum of suitable characteristics. It is usually unsuitable for the production of lubricating oil or wax and may be used for cracking stock or oil fuel.

SLUDGE. (1) *See* Acid Sludge.

(2) The sediment obtained during the deterioration of lubricating oils in use or in accelerated ageing tests.

SOFT PARAFFIN. *See* Paraffinum Molle.

SOLAR OIL. Term formerly applied to a light gas-oil distillate usually from Gulf Coast, Mid-Continent, and certain Russian petroleums.

SOLUBLE OILS. Term applied to oils which readily form stable emulsions or colloidal solutions on simple mixture with water. They usually contain metallic or ammonium soaps, or sulphonated oils, and may be used for cutting oils, detergents, insecticides, &c.

SOLVENT NAPHTHA. Term restricted to coal-tar naphtha and wood naphtha, excluding petroleum distillates.

SOUR OIL. (1) An acid-treated oil before neutralization with an alkali wash or clay treatment.

(2) An oil containing sulphur compounds (mercaptans) which does not pass the Doctor Test.

SPENT ACID. *See* Acid Sludge.

SPINDLE OIL. Low-viscosity lubricating oil, used in the lubrication of high-speed machinery, especially spindles and looms.

STABILIZED GASOLINE. Gasoline from which dissolved gaseous components of high vapour pressure, such as propane and a portion of the butane, have been removed by stabilization (fractionation under pressure).

STEAM-CYLINDER STOCK. *See* Cylinder Stock.

STEAM-REFINED OIL. A product which has been brought to a desired specification by continued distillation in steam. The process is applied to cylinder stocks and petroleum asphalts.

STEAM-TURBINE OIL. *See* Turbine Oil.

STILL COKE. *See* Petroleum Coke.

STRAIGHT-RUN GASOLINE. A gasoline obtained from a crude petroleum by direct distillation, with no cracking.

STRAW OIL. Commercial term applied to a high-grade gas oil, distilled under non-cracking conditions, and suited for use as an absorption oil.

STRIPPING OIL. *See* Absorption Oil.

SUCKER-ROD WAX. *See* Rod Wax.

SWEATS, SWEATS OIL. *See* Foots' Oil.

SWEET OIL. An oil having a negative reaction to the Doctor Test, indicating the absence of hydrogen sulphide and mercaptans.

SWITCH OIL. *See* Insulating Oils.

TAR. A viscous liquid obtained by the destructive distillation of wood, peat, coal, and similar organic or bituminous materials. The term should not be applied to petroleum products.

TECHNICAL WHITE OILS. *See* White Oils.

THICKENED OILS. Mineral oils, the viscosity of which has been raised by admixture of metallic soaps, rubber, or other suitable materials.

TOPPED CRUDE PETROLEUM. A residual product remaining after the removal, by distillation or other artificial means, of an appreciable quantity of the more volatile components of crude petroleum. (A.S.T.M. Designation D. 288–36 T.)

TOPS. The unrefined distillate obtained in topping a crude petroleum. (A.S.T.M. Designation D. 288–36 T.)

TRACTOR OIL, TRACTOR FUEL. *See* Power Kerosine.

TRANSFORMER OIL. A well-refined hydrocarbon oil, of low volatility and high resistance to sludging, used as a cooling and insulating medium in oil-filled electrical transformers. *See* Insulating Oils.

TURBINE OIL. A well-refined hydrocarbon oil, of high resistance to emulsification with water, used for the lubrication of steam turbines.

TURPENTINE SUBSTITUTE. *See* Petroleum Spirits, White Spirit.

VASELINE. A trade name for a variety of petrolatum.

VASELINE OIL. *See* Petrolatum Liquidum.

WASH OILS. *See* Absorption Oil.

WATER-SOLUBLE OILS. *See* Soluble Oils.

WAX. Term commonly used in the petroleum industry for paraffin wax.

WAX DISTILLATE. The lubricating-oil distillate from a paraffin- or mixed-base petroleum, containing a high proportion of solid paraffin hydrocarbons. It may be dewaxed directly for the production of wax and neutral oils, or may need a further cracking distillation to transform the wax into a crystallizable form for satisfactory pressing.

WAX OIL. *See* Paraffin Distillate.

WEATHERED CRUDE PETROLEUM. The product resulting from crude petroleum through loss due to natural causes, during storage and handling, of an appreciable quantity of the more volatile components. (A.S.T.M. Designation D. 288–36T.)

WET GAS. A gas containing a relatively high proportion of readily condensable constituents, e.g. a natural gas of high recoverable gasoline content. *See* Natural Gas.

WHITE OILS, TECHNICAL WHITE OILS. Generic name applied to highly refined, colourless, hydrocarbon oils, of low volatility, and covering a wide range of viscosities. They are widely used for medicinal and pharmaceutical purposes, and in the lubrication of food and textile machinery. *See* Paraffinum Liquidum, Petrolatum Liquidum.

WHITE SPIRIT. A refined petroleum distillate, intermediate between gasoline and kerosine, having volatility and other characteristics suiting it for use as a thinning medium for paints and varnishes. White spirit normally has a boiling range between 140 and 220° C., and a flash-point not lower than 78° F. *See* Petroleum Spirits.

WHITE SPIRITS. *See* Petroleum Spirits.

WILD GASOLINE. Natural gasolines, of high vapour pressure, prior to stabilization or debutanization. *See* Natural Gasoline.

NOMENCLATURE OF THE BITUM

By P. E. SPIELMANN, Ph.D., B.Sc., F.I.C., A.Inst.P., A.R.C.S., M

Consulting Chemist

G. SELL

THIS subject has for a long time been one of considerable complexity. Many schemes have been suggested, the chief of which are those of:

Clifford Richardson, *The Modern Asphalt Pavement* (1908) and elsewhere.

Holde, *Petroleum*, **7**, 713 (1912).

H. Abraham, *Asphalts and Allied Substances* (1913, onwards).

The American Society for Testing Materials (1918, onwards).

Le Gavrian and Ferret, *Chim. et Ind.* **9**, 837 (1923).

None has obtained wide acceptance, and only a few individual terms have survived.

Most troublesome of all has been the dissipation of the confusion of meaning of the words 'bitumen' and 'asphalt'. The final attempt to establish the signification of these two words has been part of a logical and coherent scheme that has gone [...] to obtain universal approval. This has very properly been undertaken by an organization of international character associated with road construction, because most of the bitumen and asphalt that is produced is used for this purpose all over the world.

Arising from the 5th International Road Congress, held at Milan in 1926, the first meeting of a Standardizing Committee took place in Paris in 1927 (*Roads and Road Construction*, **6**, 288 (1928)). Members representing the following countries were included in the committee: France, Belgium, Denmark, Great Britain, Holland, Italy, Spain, Switzerland, and the U.S.A. Complete unity of agreement was found impossible, in that the United States agreed only to the definition adopted for Bitumen—her own definition that had been adopted unaltered—but complete understanding was achieved as to the definite and clear meaning of the various words.

These definitions are the following:

BITUMEN. Mixtures of hydrocarbons of natural or pyrogeneous [*sic*] origin or combinations of both (frequently accompanied by their non-metallic derivatives) which can be gaseous, liquid, semi-solid or solid and which are completely soluble in carbon disulphide.

Whatever may be thought of the value of a definition that covers so enormous a range of materials under one name, experience has shown that it does take its place logically in the whole scheme.

It is to be noticed that the introduction of the word 'pyrogeneous' brings the CS_2-soluble substances of tar under the definition.

ASPHALTIC BITUMEN. Natural or naturally occurring bitumen, or bitumen prepared from natural hydrocarbons by distillation or oxidation or cracking; solid or viscous, containing a low percenta
possessing characteristic ag
and substantially soluble in car

This term is not used in the Unitec

The significance of this definition i
all the bitumens those few that give a

ASPHALT. Natural or mechanical

asphaltic bitumen is a
matter.

The word 'asphalt' is
ing the origin of the pr

U.S.A. definition: Black to
materials which gradually
the predominating constit
occur in the solid or se
obtained by refining pet
tions of the bitumens me
petroleum or derivatives t

The significance of this
embedded in the industry
different meanings could n

TAR. A bituminous prod
from the destructive o
The word 'tar' must al
of the matter from whi
peat, vegetable matter,
should also be indicated

U.S.A. definition: Black t
condensates, which yield sul
when partially evaporated or fra
which are produced by destructive
material, such as coal, oil, lignite, p

PITCH. Black or dark brown solid o
and agglomerative residue rem
evaporation or fractional distilla
products.

There might well be inserted here an
tion of origin, as is given for 'Tar'.

Tar and pitch are included here in
their precise position in relation to the
with which they were becoming confuse
increasing use in road construction.

These are the five definitions of bitum
materials that have become establish
agreement, though there is some doub
ceptance of that for asphalt, but this will
at the next (and perhaps last) meeting
It is possible also that one or two edit
made in the definitions of tar and pitch
wide acceptance, as can be judged by
technical literature. In Great Bri
adopted by the Institution of Petr
official representative of petro
Standardization of Tar Pr
representing the British Tar
dards Institution, in

ıwarz, in a paper under the *Legal Aspect*, put forward me of the Zentralstelle für ıe Deutsche Verband für :chnik, and the Deutsche

rring in nature)

›luble in carbon disulphide, *Example*: Sapropel wax,

ble in carbon disulphide and *·ample*:

and 3. CS_2-sol. material
on in (*a*) Asphaltite
(*b*) Natural Asphalt
(*c*) Asphalt Rock
solid

roleum distillation residues
·affinic
ĸed base
›haltic

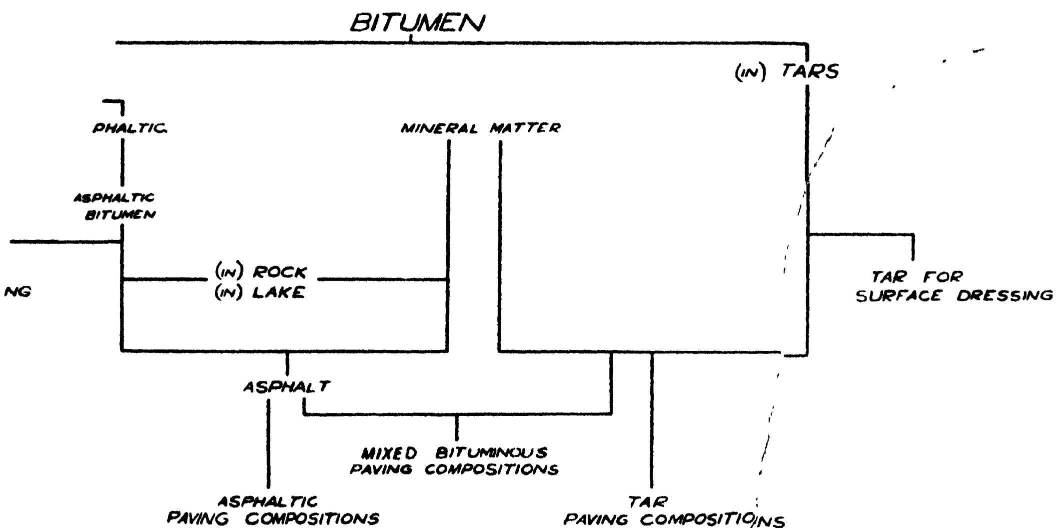
B. Refinery residues (obtained by chemical treatment of materials under I A, I B, and II A)
Acid tars of all kinds.

This was supplemented in discussion by Dr. Temme, representing the Arbeitsgemeinschaft der Bitumen-Industrie, E.V. Berlin, but he wished the word 'bitumen' to be added in brackets wherever the word 'asphalt' was given: this would indeed plunge the position back into the chaos of pre-1926.

There remain certain other terms which are not yet accepted officially. Some are included in *The Technical Dictionary of Road Terms in Six Languages*, which has been produced by the Paris Committee in tentative form (1931) and which is undergoing revision in the light of a number of years' experience. Two British committees are also sitting for the revision of the English words.

ASPHALTITE. A naturally occurring substance allied to asphaltic bitumen, soluble in carbon disulphide 40–100%, having a softening point (Ring and Ball) above 240° F.

Examples: Oxy-asphaltite, Thio-asphaltic, Grahamite, Gilsonite, Manjak



1. Classification of bituminous road materials. (*By the courtesy of the British Standards Institution.*)

/ soluble in carbon disulphide and mainly . *Example*: elaterite, peat, coal, oil shale.

ʼI. ALLIED MATERIALS

(artificially produced by destructive ganic matter).

ʻs are called Tar Oils; the residue Tar ʻ origin is to be stated.

ʻained directly or by further treat- ʻ*repared tars.*

2. Pitches

ʻstructive distillation of

ALBERTITE. A mixture of asphaltic bitumen with finely divided organic matter that is insoluble in carbon disulphide.

With regard to the *constituents of these bituminous substances*, the significance of the terms that were originally suggested have scarcely changed.

PETROLENES. Obsolescent, *see* Malthenes.

MALTHENES. Soluble in carbon disulphide, carbon tetrachloride, and standard petroleum naphtha.

ASPHALTENES (Hard Asphalt). Soluble in carbon·disulphide and carbon tetrachloride, but insoluble in standard petroleum naphtha.

rbon disulphide, but insoluble in ᴊe.

›halt). Soluble in carbon disulphide, ıixture of equal parts by volume of gr. 0·72°)—and ethyl alcohol (96%).

:se J. E. Hackford (*Mining and Metal-* ; *J.I.P.T.* **8**, 201 (1922)) introduced the

following terms, which have here been edited t
considerable degree.

KERITE. A naturally occurring bituminous substa
posed appreciably or wholly of kerotene.

Examples: Oxy-kerite Albertite, Elaterite
Thio-kerite Wurtzilite, Impsoni

KEROTENE. The component in kerite that is ins
carbon disulphide.

KEROL. The component in kerotene that is so
pyridine and in chloroform.

KEROLE. The component in kerotene that is sol
pyridine, but insoluble in chloroform.

There are a few unimportant exceptions to th
national scheme, resulting from terms being too
current use to be easily altered; but even these are
resistive:

SECTION 2

STATISTICS

STATISTICS OF PETROLEUM AND ALLIED SUBSTANCES

By GEORGE SELL, M.Inst.P.T.

Petroleum Times

Petroleum

THE first recorded production of crude petroleum was in 1857, when Rumania had an output of 275 metric tons. In 1859 the United States of America first produced petroleum on a commercial basis, the production for that year being 274 metric tons. The next country to yield petroleum in quantities sufficient to be recorded was Italy, which first produced in 1860, although the total quantity obtained from that year until 1890 was only about 6,000 metric tons. In 1862 Canada commenced to give a yield of crude petroleum, and in 1863 Russia entered the field.

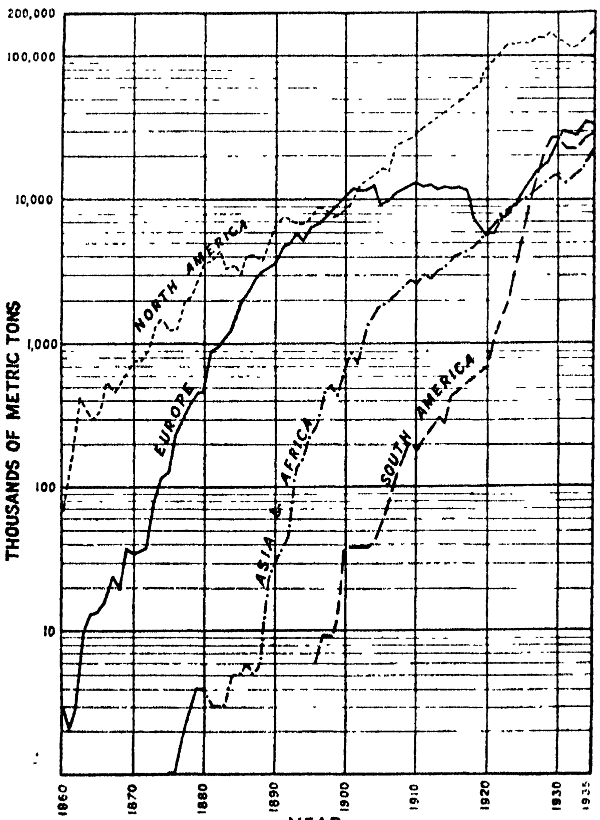


FIG. 1.

In Table I full details of the annual production in the various countries are given, the total to the end of 1935 being 3,776,227,000 metric tons. Of this quantity, 2,408,571,000 metric tons, or about 64%, has been obtained from the United States of America, while the U.S.S.R., second in order of total production, is responsible for 12·3% only. Garfias and Whetsel estimate the world's production in 1936 to have been 1,780,880,000 bbl., or approximately 247,000,000 metric tons [*Petr. Times*, 16 Jan. 1937].

In Fig. 1 the figures in Table I have been grouped under continents, Asia and Africa being included together for convenience. From this point of view the total world's production to the end of 1935 has been distributed as follows: North America, 72%; Europe, 16%; Asia and Africa, 6%; South America, 6%. From the graph it will be seen that, ignoring minor fluctuations, the curves of each continent show a general trend. In all cases there appears to be a flattening of the curves in recent years. During the period 1930 to 1935 all the continents showed a general decline followed by a rise tending to bring the curves back to normal. Even in the case of Europe, the curve for which shows a deep depression in the War and post-War years, it appears that the normal slope has been almost reached in 1935.

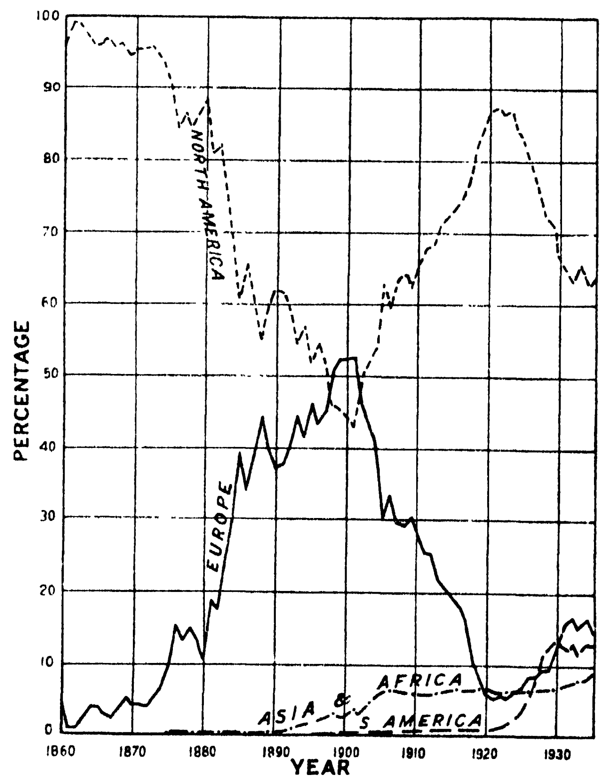


FIG. 2.

In Fig. 2 the production by continents has been plotted on the basis of the percentage of the world's total production, and the relationship of the four continents is clearly shown.

Petroleum Refining

In Table II such details as are available are given regarding the output of petroleum refineries in various countries, and, as is to be expected, the United States of America leads in this respect.

No information is available regarding the actual refinery capacity of these countries, except in the case of the United States, the details of which are given in Tables III, IV, and V.

In Table III the total number of refineries, their capacity and status for the years 1925 to 1935 are given, and in Table IV the refineries in existence on 1 January 1935 are listed in accordance with the type of process operated.

Table V deals with cracking operations in the United States during 1925 to 1935, and illustrates the rapid development which has taken place in this method of treatment. In less than 10 years the operating capacity of cracking plants in that country has nearly trebled.

Generally speaking, it can be said that the figures of refinery activity in the United States are indicative of the position throughout the world.

Consumption of Petroleum Products

In Table VI, which has been prepared by V. R. Garfias and R. V. Whetsel, the world's consumption of petroleum products is given for the years 1931 to 1935. From this it will be seen that, although there was a decrease in the demand in the year 1932, the figure for 1935 is about 13% higher than for 1931. The consumption in 1936, according to preliminary estimates, is 1,760,000,000 bbl. [*Petr. Times*, 16 Jan. 1937].

Natural Gas

Table VII sets out the production of natural gas in various countries since the year 1903. In many cases natural gas was produced in the countries mentioned prior to the first year for which a figure is given, but either no statistics are available or only a value is given in the official records with no information regarding the quantity. It is the custom in some countries to record only the quantity of natural gas actually consumed, and in some cases no statistics are available either for production or consumption.

Oil Shale

The annual production of oil shale in different countries since 1901 is given in Table VIII. This material is only actively exploited in those countries which are devoid, or practically devoid, of crude petroleum as such. The United Kingdom has produced the largest quantity of oil shale, practically the whole of which has been obtained from Scotland.

Natural Asphalt and Asphalt Rock

Natural asphalt and asphalt rock has been exploited in many countries, as shown in Table IX, where figures are given for the annual production since 1901.

Acknowledgements

Wherever possible the figures given in the tables have been compiled from official sources direct, and much information has been obtained from the annual publication of the United States Bureau of Mines (*Minerals Yearbook*) and from *Mineral Industry of the British Empire and Foreign Countries. Statistical Summary*, published yearly by the Imperial Institute, London.

TABLE

World's Production

In thousands

Year	U.S.A.	U.S.S.R.	Mexico	Venezuela	Netherlands East Indies	Roumania	Iran	India	Poland	Peru	Columbia	Argentina
1857–60	68†					3‡						
1861	288					2						
1862	418					3						
1863	357	5				4						
1864	289	9				4						
1865	342	9				5						
1866	493	11				5						
1867	457	16				7						
1868	498	12				8						
1869	576	28				8						
1870	720	23				11						
1871	712	23				13						
1872	861	25				13						
1873	1,354	66				14						
1874	1,496	81				14			21			
1875	1,203	96				15			22			
1876	1,250	198				15			23			
1877	1,828	254				15			24			
1878	2,109	338				15			24			
1879	2,728	386				15			30			
1880	3,600	406				16			32			
1881	3,788	834				17			40			
1882	4,157	846				19			46			
1883	3,212	980				19			51			
1884	3,318	1,458				29			57			
1885	2,994	1,884				27			65			
1886	3,844	2,015				23			43			
1887	3,874	2,621				25			48			
1888	3,782	2,981				30			65			
1889	4,816	3,145				41		13	72			
1890	6,276	3,702				42		20	92			
1891	7,436	4,488				51		27	88			
1892	6,919	4,693				56		34	90			
1893	6,633	5,320			80	57		42	96			
1894	6,759	4,874			92	65		46	132			
1895	7,244	6,182			162	77		52	215			
1896	8,350	6,327			190	78		60	340	6		
1897	8,284	6,920			340	88		77	310	9		
1898	7,584	7,960			395	141		76	323	9		
1899	7,817	8,604			240	183		132	322	12		
1900	8,714	9,841			300	225		152	326	38		
1901	9,504	10,996	2		535	233		201	452	38		
1902	12,159	10,426	6		324	287		227	576	39		
1903	13,762	10,314	11		769	384		353	728	38		
1904	16,038	10,716	19		868	501		476	827	40		
1905	18,454	7,499	38		1,064	615		582	802	51		
1906	17,327	8,036	75		1,101	887		564	760	73		
1907	22,753	8,439	151		1,346	1,129		611	1,176	109		
1908	24,456	8,485	590		1,387	1,148		709	1,754	129		‖ 2
1909	25,091	9,001	407		1,475	1,296		938	2,077	193		3
1910	28,705	9,597	545		1,496	1,352		863	1,763	172		3
1911	30,198	9,030	1,883		1,671	1,545	25	907	1,463	201		2
1912	30,539	9,281	2,484		1,478	1,805	80	1,000	1,187	240		7
1913	34,033	8,573	3,855		1,534	1,847	229	1,115	1,087	284		19
1914	36,405	9,145	3,936		1,569	1,810	356	1,042	878	252		39
1915	38,506	9,353	4,938		1,644	1,588	438	1,153	730	353		73
1916	41,201	9,933	6,083		1,730	899	605	1,194	919	355		124
1917	45,933	9,550	8,296	18	1,701	724	847	1,136	850	353		173
1918	48,756	5,520	9,577	51	1,764	969	1,071	1,151	823	346		193
1919	51,831	4,412	13,064	46	2,160	856	1,337	1,228	832	360		190
1920	60,675	3,832	23,566	70	2,365	1,109	1,680	1,177	766	386		236
1921	64,682	3,972	29,017	218	2,359	1,168	2,216	1,228	705	507	9	294
1922	76,374	4,864	27,349	335	2,382	1,373	2,846	1,199	713	768	45	409
1923	100,371	5,435	22,443	639	2,833	1,512	3,582	1,182	737	781	60	476
1924	98,024	6,301	20,957	1,331	2,926	1,851	4,246	1,183	771	1,148	63	665
1925	104,622	7,295	17,332	2,998	3,066	2,317	4,573	1,163	812	1,265	142	855
1926	106,474	8,899	13,567	5,207	3,018	3,241	4,839	1,126	796	1,478	908	1,121
1927	123,486	10,554	9,621	8,769	3,694	3,661	5,310	1,127	716	1,387	2,115	1,233
1928	123,592	11,634	7,524	15,319	4,308	4,269	5,719	1,229	736	1,645	2,802	1,296
1929	138,104	13,659	6,705	19,845	5,239	4,837	5,548	1,230	669	1,839	2,871	1,341
1930	123,117	18,612	5,931	20,154	5,532	5,744	6,034	1,249	663	1,705	2,866	1,286
1931	116,683	22,324	4,957	17,192	4,698	6,658	5,825	1,225	630	1,382	2,569	1,762
1932	107,645	21,496	4,922	17,085	4,898	7,350	6,549	1,239	557	1,356	2,306	1,877
1933	122,536	21,434	5,090	17,273	5,417	7,387	7,200	1,229	551	1,535	1,853	1,956
1934	122,931	24,210	5,725	20,015	5,907	8,473	7,658	1,294	529	2,235	2,442	2,003
1935	136,156	24,140	6,014	21,928	6,082	8,385	7,600	1,297	515	2,307	2,478	2,042
TOTAL	2,408,571	464,628	266,680	168,493	92,139	90,708	86,413	35,558	33,547	25,424	23,529	19,680
PERCENTAGE OF GRAND TOTAL	63 782	12 304	7·062	4·462	2 440	2 402	2 290	0 942	0 889	0·673	0·623	0·521

* 1 metric ton = 1,000 kilograms = 2,204·6223 lb. av.

Where it has been necessary to convert from volumetric units, the following have been taken as equivalent to 1 metric ton: Mexico, 6·665 bbl.; India, 249 Imp. gal.; Peru, 7·3 bbl.; Colombia, 7·1 bbl.; Argentina, 1·113 cu. m.; Trinidad, 7·2 bbl.; Japan and Formosa, 6·498 koku; Canada, 7·776 bbl.; Ecuador 7·1 bbl.; Iraq, 7·6 bbl.

† The first recorded production in the U.S.A. was 274 metric tons in 1859.

I

of Crude Petroleum

of metric tons.*

Trinidad	Japan and Formosa	Sarawak and Brunei	Iraq	Canada	Germany	Egypt	Sakhalin	Ecuador	France	Italy	Czecho-slovakia	Bolivia	Total
													71
													290
				2									423
				11									377
				12									314
				14									370
				22									531
				24									504
				26									544
				28									640
				32									786
				35									783
				40									939
				47									1,481
				22									1,634
	1			28									1,365
	1			40									1,527
	2			40									2,163
	3			40									2,529
	4			74									3,237
	4			45	1								4,104
	3			47	4								4,733
	3			50	8								5,129
	3			61	4								4,330
	5			73	6								4,946
	5			76	6								5,057
	6			75	10								6,016
	5			92	10								6,675
	6			89	12								6,965
	9			91	10								8,197
	8			102	15					6§			10,263
	9			97	15					1			12,212
	11			100	14					3			11,920
	14			103	14					3			12,362
	23			107	17					3			12,118
	23			93	17					4			14,069
	32			93	20					3			15,499
	36			91	23					2			16,180
	43			98	26					2			16,657
	73			104	27					2			17,516
	118			91	50					2			19,857
	151			80	44					2			22,238
	163			68	50					3			24,328
	164			63	63					3			26,652
	192			65	90					4			29,836
	200			82	79					6			29,472
	232			73	81					7			29,216
	272			101	106					8			36,201
	280			68	142					7			39,157
1	272			54	143					6			40,957
9	234			41	145					7			44,932
36	236			37	142	3				10			47,389
64	225			31	130	28				7			48,586
82	263	20		29	121	13				7			53,111
126	371	46		28	110	100				6			56,219
139	422	56		28	99	30				6			59,556
129	406	92		25	93	58				7			63,853
223	390	78		27	91	137		8		6			70,541
289	332	73		39	89	282		8		5			71,338
256	325	86		31	37	232		8	47	5	7		77,350
289	322	151		25	35	148		8	55	5	10		96,910
327	324	203		24	38	183		8	56	5	14		107,557
340	298	410		23	42	173	1	8	70	4	18		120,044
424	262	567		22	51	153	1	12	71	5	11		141,630
563	262	602		21	59	163	12	14	71	5	11		141,249
609	273	613		43	79	180	13	23	66	8	23		148,370
690	259	713		47	95	173	28	30	68	5	22		152,804
747	259	712	82	61	97	184	69	76	73	6	16		174,055
1,067	282	751	40	80	92	269	106	153	74	6	14		183,007
1,210	266	760	32	144	104	272	168	195	77	6	14		205,135
1,308	279	702	42	196	170	285	267	219	76	8	23	7	196,475
1,353	238	535	32	198	229	285	405	248	74	16	20	3	189,541
1,406	230	527	12	134	230	271	415	225	75	27	18	5	180,855
1,328	230	623	21	148	239	232	400	228	79	27	18	14	197,048
1,513	289	700	978	181	315	215	400	230	78	20	26	20	208,428¶
1,622	300	690	3,600	184	427	170	400	244	75	17	30	21	226,874¶
16,150	9,953	9,710	4,839	4,816	4,466	4,239	2,685	1,945	1,185	313	295	70	3,776,227¶
0·428	0·264	0·257	0·128	0·127	0·118	0·112	0·071	0·051	0·031	0·008	0·008	0·002	100·000

‡ The production in Roumania in the years 1857 to 1860 was 275, 495, 605, and 1,188 metric tons respectively.
§ Includes the total production in Italy for the years 1860 to 1890.
|| The production in Argentina in 1907 was 14 metric tons.
¶ Including Bahrein Island, 41,000 metric tons in 1934 and 150,000 metric tons in 1935 (0·005% of grand total).

Table II

Production of Refined Petroleum Products

Country	Year	Motor spirit	Other spirit	Kerosine	Gas oil, fuel oil, and diesel oil	Lubricating oil	Road oil	Other oils	Asphalt	Coke	Paraffin wax
		Thousands of Imperial gallons*							Tons		
Argentina	1931	151,235	..	25,922	312,405	..	..	..	..	..	..
	1932	172,116	..	32,217	302,796	..	..	..	..	..	..
	1933	164,337	..	30,510	304,097	7,848	..	..	10,437	..	..
	1934	180,750	..	32,923	307,960	7,776	..	..	8,826	..	..
	1935	214,000	..	38,924	243,860†	10,270	..	..	12,360	..	..
Barbados	1933	128	..	182	1,087	..	..	..	..	..	..
	1934	88	..	135	806	..	..	..	..	..	..
	1935	134	..	176	950	.	.	..	.	..	..
British Borneo (Sarawak)	1933	26,347	..	9,460	121,675	..	..	..	..	..	..
	1934	26,380	..	4,640	136,570	..	..	..	..	..	..
	1935	19,725	..	9,644	149,310	.	.	..	..	..	..
Canada	1931	469,925	8,492	39,466	428,753	15,212	..	..	172,441	64,588	4,508
	1932	399,937	18,182	52,525	366,274	15,144	.	..	104,919	65,237	4,105
	1933	422,937	34,019	49,028	430,314	17,250	.	..	98,308	66,719	4,017
	1934	461,755	36,214	37,740	456,000	18,220	..	..	116,787	55,143	4,757
	1935	513,715	48,560	31,835	469,970	17,150		..	157,586	64,456	5,017
Colombia	1933	10,360	10	2,320	17,530	530	..	..	3,469	..	..
	1934	14,140	30	3,130	34,480	660	..	..	2,874	..	..
	1935	15,430	28	2,800	35,300	950	.	..	3,440	..	..
Ecuador	1931	1,516	..	490	372	‡	..	..	..	..	..
	1932	‡	..	‡	‡	‡	..	..	..	..	..
	1933	1,791	..	470	895	37	..	..	..	..	..
	1934	1,930	..	740	1,130	70	..	..	..	..	..
	1935	2,900	..	1,740	1,390	65	..	..	..	..	..
Egypt	1931	24,668	..	6,674	49,188	..	..	..	40,028	.	..
	1932	26,880	..	5,362	42,060	..	..	..	57,269	..	..
	1933	25,680		4,360	36,170	..	..	..	47,872	..	.
	1934	23,490	..	7,240	31,380	..	..	..	57,637	..	..
	1935	22,520	..	6,990	36,220	..	..	..	91,004	.	.
Formosa	1931	6,552	..	633	..	..	..	..	..	..	..
	1932	4,826	..	399	..	..	..	..	..	..	..
	1933	2,180	..	423	176	49	..	..	..	..	..
	1934	2,660	..	439	168	22	..	..	.	..	..
	1935	1,770	.	550	1,324	904	..	..	..	..	.
France	1931	28,156	..	7,345	35,151	11,622	17,860	..	79,639§	4,486	881
	1932	97,120	..	12,993	68,785	14,829	34,381	..	149,155§	6,401	732
	1933	228,245	.	31,027	226,804	30,330	52,290	..	‡	9,217	3,166
	1934	472,467	2,387	39,156	435,448	55,528	59,406	..	‡	10,592	2,750
	1935	460,088	132,186	50,978	554,452	64,695	63,813	..	‡	5,863	3,811
Germany	1931	121,238	..	3,740	31,928	77,175	..	66,225‖	..	..	11,900
	1932	124,653	..	5,472	37,492	74,025	..	‡	..	..	‡
	1933	133,681	..	5,060	56,082	33,432	..	..	‡	..	15,600
Great Britain	1931	180,200	20,900	53,400	229,300	19,000	..	6,300	385,697¶	..	..
	1932	159,300	17,000	43,000	196,000	19,100	..	5,300	376,321¶	..	..
	1933	149,400	20,700	38,400	188,000	19,100	..	10,200	402,297¶	..	..
	1934	144,800	24,400	34,500	186,800	24,700	..	100	488,202¶	..	.
	1935	133,800	20,100	33,500	212,400	25,700	..	..	491,041¶	..	..
Hungary	1933	13,380	..	14,764	5,560	1,866	..	..	..	..	4,000
	1934	13,310	..	15,427	6,700	2,070	..	..	..	..	6,100
	1935	16,870	..	16,247	10,760	3,030	..	..	..	..	6,220
India	1931	63,817	..	162,847	38,854	9,193	..	5,977	13	..	49,397
	1932	68,015	..	159,775	‡	‡	..	‡	‡	..	‡
	1933	70,520	..	138,028	‡	‡	..	‡	‡	..	‡
	1934	79,213	..	167,754	†	‡	..	‡	‡	..	‡
	1935	88,270	..	163,925	†	‡	..	‡	‡	..	‡
Iraq	1933	6,405	..	4,125	..	..	..	..	..	..	..
	1934	3,878	..	4,271	13,567	..	..	..	..	..	..
	1935	4,011	..	4,305	13,860	..	..	..	..	..	..
Italy	1931	39,921	7,068	..	26,452	4,375	..	851	..	32,536	523
	1932	47,090	9,798	..	36,044	5,398	..	458	..	31,157	645
	1933	48,936	12,663	..	38,430	6,176	..	650	..	33,880	763
	1934	37,761	..	10,244	27,362	4,967	..	134	..	36,815	‡
	1935	30,939	..	13,497	30,681	5,743	..	134	..	19,385	‡
Japan	1931	64,568	..	13,508	42,310	36,157	..	..	..	..	..
	1932	81,750	..	17,988	48,760	36,626	..	..	..	..	..
	1933	87,108	..	17,105	64,050	40,464	..	..	74,518	..	1,618
	1934	107,604	..	16,665	87,925	46,680	..	..	56,042	..	11,169
	1935	124,958	..	22,330	99,625	57,432	..	..	67,439	..	12,451
Mexico	1931	147,350	..	75,985	460,880	16,345	..	..	166,911	.	40,758
	1932	164,250	..	60,410	516,640	20,230	..	..	138,803	1,955	30,682
	1933	239,890	..	52,675	659,565	17,430	..	..	149,031	3,391	19,777
	1934	302,278	..	69,336	818,998	16,512	..	..	285,155	1,845	23,691
	1935	297,550	..	64,790	742,521	21,372	..	..	302,333	..	32,348
Netherlands East Indies	1931	423,543	..	175,849	355,642	6,596	..	..	8,793	‡	52,828
	1932	396,426	..	192,258	416,064	4,826	..	2,778**	7,131	918	47,968
	1933	434,970	..	196,835	480,890	5,314	..	2,603	7,525	..	54,285
	1934	446,665	8,270	218,257	488,068	6,054	..	1,666	6,996	..	69,927
	1935	525,548	11,105	220,927	509,904	5,420	..	1,505	10,0[illegible]	..	57,488
Netherlands West Indies (exports)	1933	665,839	..	77,240	2,351,189	27,533	..	..	[illegible]	..	..
	1934	739,667	..	52,532	2,561,511	35,837	..	..	.	..	..
	1935	993,090	..	128,097	2,966,076	47,918	..	..	.	..	..

TABLE II (*cont.*)

Country	Year	Motor spirit	Other spirit	Kerosine	Gas oil, fuel oil, and diesel oil	Lubricating oil	Road oil	Other oils	Asphalt	Coke	Paraffin wax
		Thousands of Imperial gallons*								Tons	
Peru	1931	70,315	..	15,396	65,086	1,141	..	..	228	435	..
	1932	93,820	.	22,965	61,440	1,060	..	..	217	319	..
	1933	89,637	24	18,642	77,503	1,136	..	..	602	326	..
	1934	95,980	637	20,971	89,062	1,395	..	..	1,299	367	..
	1935	77,328	‡	43,122	88,503	1,080	..	..	1,080	266	..
Poland	1931	30,988	..	47,570	29,584	21,008	..	11,909	21,588	8,801	31,089
	1932	27,420	..	43,408	26,960	18,123	..	10,772	18,836	7,586	27,106
	1933	27,224	..	47,185	25,958	19,770	..	10,952	21,834	6,613	28,779
	1934	25,722	..	46,480	23,181	19,087	..	7,608	22,475	4,925	27,858
	1935	25,674	.	39,880	23,806	16,986	.	.	24,322¶	..	24,712
Roumania	1931	443,787	24,468	315,291	752,028	21,807	..	1,645	32,723	11,384	7,857
	1932	486,238	39,970	289,402	815,506	17,860	..	484	37,938	19,666	7,133
	1933	483,494	34,221	281,680	875,655	18,064	..	18,161	58,371	21,218	8,097
	1934	531,529	89,391	284,578	978,665	18,565	..	12,866	82,887	30,594	7,407
	1935	556,250	.	369,938††	983,035	19,415	..	7,888	66,934	33,835	7,697
U S A.	1931	15,091,009	.	1,484,445	11,784,600	933,907	181,053	145,136	2,656,994	1,814,370	213,125
	1932	13,731,031	..	1,533,407	10,308,160	784,540	240,576	60,782	2,209,855	1,597,220	204,875
	1933	14,044,665	..	1,712,851	11,066,680	831,473	193,538	50,186	2,193,008	1,410,782	209,625
	1934	14,544,213	..	1,870,332	11,374,300	918,520	269,290	67,182	2,536,847	1,160,770	209,250
	1935	16,029,220		1,953,555	12,569,908	933,006	232,510	.	2,898,929	1,301,786	201,000
U.S S R.	1931	827,190	..	1,045,110	‡	160,550	..	..	‡	..	‡
	1932	864,950	..	963,627	2,197,828	167,325			106,600	..	15,100
	1933	651,175	.	1,046,595	1,748,830	267,744	..	..	143,900	..	18,400
	1934	693,387	..	1,213,850	‡	339,040	.	.	251,000	..	30,000
	1935	917,135	.	1,321,100	‡	317,760	.	.	‡	..	‡
Venezuela	1933	29,633	..	802	210,228	.	..	779	.	..	..
	1934	32,196	..	1,042	234,728	.	..	1,257	.	..	.
	1935	30,975	..	910	240,065		..	350		..	.

* Where it has been necessary to convert from weight units, the following have been taken as equivalent to 1 ton: Motor spirit 305 Imp. gal.; Kerosine 275 Imp. gal., Gas oil 260 Imp. gal.; Diesel oil 256 Imp. gal., Fuel oil 240 Imp. gal.; Lubricating oil 240 Imp. gal., Road oil 240 Imp. gal., Other oils 250 Imp. gal.
† Fuel oil only. No information available for gas oil and fuel oil. ‡ Not available. § Pitch. ‖ Including also solid products.
¶ Including paraffin wax and pitch. ** Batching oil. †† Including white spirit.

TABLE III

Summary of Refinery Capacity in the United States

Jan. 1	Number: Operating	Number: Shut down	Number: Building	Number: Total	Capacity (bbl. per day): Operating	Capacity: Shut down	Capacity: Building	Capacity: Total
1925	357	184	6	547	2,489,927	337,910	37,000	2,864,837
1926	352	158	2	512	2,562,357	290,610	5,500	2,858,467
1927	327	138	7	472	2,834,282	226,725	61,000	3,122,007
1928	326	97	5	428	3,036,125	214,255	22,000	3,272,380
1929	341	72	14	427	3,325,890	183,650	99,000	3,608,540
1930	358	54	8	420	3,634,825	130,760	37,200	3,802,785
1931	346	89	10	445	3,706,610	236,075	45,000	3,987,685
1932	365	108	6	479	3,624,992	389,616	8,720	4,023,328
1933	372	133	18	523	3,445,118	444,392	31,545	3,921,055
1934	454	137	13	604	3,553,569	364,648	44,450	3,962,667
1935	435	196	7	638	3,614,749	443,751	13,900	4,072,400

TABLE IV

Refinery Capacity in the United States on 1 Jan. 1935 by Types of Process

Type of process	Number: Operating	Number: Shut down	Number: Building	Number: Total	Capacity (bbl. per day): Operating	Capacity: Shut down	Capacity: Building	Capacity: Total
Skimming	271	170	7	448	1,080,254	397,376	13,900	1,491,530
Complete	79	3	..	82	1,821,650	10,000	..	1,831,650
Skimming and lube	24	6	.	30	304,400	5,600	..	310,000
Skimming and asphalt .	33	1	..	34	303,400	1,200	..	304,600
Skimming, lube, and asphalt .	1	..	.	1	20,000	..	..	20,000
Lube .	6	4	.	10	2,870	13,140	..	16,010
Asphalt .	11	4	..	15	44,200	3,300	.	47,500
Topping .	10	8	..	18	37,975	13,135	.	51,110
Total .	435	196	7	638	3,614,749	443,751	13,900	4,072,400

TABLE V

Summary of Cracking Capacity in the United States

Date	Charging capacity (bbl. per day): Operating	Shut down	Building	Total
1 June 1925	690,492	26,200	116,000	832,692
1 June 1926	844,800	47,690	47,600	940,090
1 Jan. 1928	1,013,000	253,000	22,000	1,288,000
1 Jan. 1929	1,194,501	147,923	134,450	1,476,874
1 Jan. 1930	1,419,200	139,840	149,900	1,708,940
1 Jan. 1931	1,594,990	244,661	111,130	1,950,781
1 Jan. 1932	1,603,809	394,585	48,587	2,046,981
1 Jan. 1933	1,580,051	417,694	33,650	2,031,395
1 Jan. 1934	1,712,629	377,735	59,300	2,149,664
1 Jan. 1935	1,897,778	311,491	20,000	2,229,269

TABLE

World Consumption of Petroleum

By V. R. GARFIAS and R. V. WHETSEL,

(Thousands

	1931						1932						1933		
	Motor fuel	*Kero-sine*	*Gas and fuel oil*	*Lubri-cants*	*Miscel-laneous*	*Total*	*Motor fuel*	*Kero-sine*	*Gas and fuel oil*	*Lubri-cants*	*Miscel-laneous*	*Total*	*Motor fuel*	*Kero-sine*	*Gas and fuel oil*
United States .	407,843	31,296	336,698	20,094	106,408	902,339	377,791	33,221	308,157	16,614	99,699	835,482	381,561	38,440	321,395
Russia . .	5,400	19,800	56,700	2,700	5,400	90,000	7,607	23,464	58,492	5,292	4,260	99,115	8,838	24,722	51,818
United Kingdom	28,437	6,430	18,713	2,820	1,760	58,160	30,328	5,283	19,280	2,462	1,810	59,163	33,220	5,480	21,900
France . .	19,165	1,898	6,941	1,932	1,810	31,746	19,571	1,584	8,828	1,768	1,814	33,565	21,268	1,522	12,594
Canada . .	16,151	1,316	13,800	836	1,645	33,748	14,435	1,558	13,153	746	2,060	31,951	15,016	1,608	13,520
Germany . .	14,540	1,246	4,647	2,326	1,976	24,735	12,789	960	3,996	2,015	1,620	21,380	12,373	841	6,429
Argentina	5,346	1,082	13,165	329	860	20,782	4,835	832	12,244	287	820	19,018	5,301	1,064	12,678
Japan . .	5,159	846	6,807	1,304	520	14,636	5,234	850	6,227	982	530	13,823	5,650	1,006	7,781
Mexico . .	1,527	487	7,017	103	4,896	14,030	1,724	567	9,820	109	2,413	14,633	1,765	583	11,091
Roumania . .	760	1,320	9,589	197	1,570	13,436	706	1,225	9,701	190	2,020	13,842	726	1,262	10,076
British India .	2,220	6,296	4,440	740	1,100	14,796	2,389	6,916	3,668	770	1,036	14,779	2,085	5,899	3,382
Italy . .	3,541	1,236	5,910	834	348	11,869	2,915	1,102	5,323	801	229	10,370	3,001	1,133	7,296
Dutch East Indies	1,867	2,489	6,098	515	1,420	12,389	1,687	2,510	5,750	531	1,356	11,834	1,500	2,275	4,610
Australia . .	6,095	1,005	1,083	313	610	9,106	5,359	990	772	313	513	7,947	5,724	1,201	2,631
Dutch West Indies	154	20	5,621	27	2,591	8,413	156	19	5,200	22	2,820	8,217	160	21	5,100
China . .	715	4,120	1,633	247	92	6,807	675	3,674	1,530	194	85	6,158	744	4,460	2,184
Iran .	423	1,280	3,300	681	1,342	7,026	461	1,200	3,200	670	1,230	6,761	673	1,285	3,259
Holland .	3,000	1,677	1,897	378	281	7,233	2,891	1,346	1,376	352	202	6,167	3,291	1,464	1,992
Venezuela . .	479	29	4,936	50	560	6,054	474	25	4,866	42	350	5,757	507	17	4,922
Brazil .	1,822	746	1,946	160	38	4,712	1,790	590	2,312	149	20	4,861	2,005	629	2,945
Sweden .	2,785	617	1,464	346	84	5,296	2,921	612	1,602	321	60	5,516	2,930	719	2,003
Spain .	3,372	161	1,734	230	290	5,787	3,122	165	1,728	210	280	5,505	3,032	215	1,502
Belgium . .	2,139	775	1,232	623	124	4,893	2,266	720	984	590	103	4,663	2,589	304	978
Denmark . .	2,116	714	1,343	303	22	4,498	1,980	639	1,605	181	14	4,419	1,840	680	1,630
Egypt . .	596	2,429	1,230	129	116	4,500	413	2,142	1,231	114	102	4,002	419	2,061	1,506
Cuba . .	847	185	3,168	76	52	4,328	699	173	2,784	52	40	3,748	504	114	2,840
Union of South Africa . .	1,913	350	449	139	161	3,012	1,901	415	404	130	147	2,997	2,149	451	560
Norway .	849	305	1,049	75	49	2,327	847	277	1,335	69	48	2,576	895	264	2,090
Philippine Islands	887	586	1,863	80	110	3,526	759	560	1,824	74	102	3,319	891	590	1,790
Czechoslovakia .	2,301	229	340	290	38	3,198	2,001	220	337	190	32	2,780	1,911	353	712
Switzerland .	1,560	189	649	146	152	2,696	1,736	194	862	150	25	2,967	1,661	186	1,014
Hawaiian Islands.	869	110	2,053	45	76	3,153	905	106	1,449	45	72	2,577	909	129	1,624
New Zealand .	1,792	110	1,050	50	48	3,050	1,669	159	968	62	41	2,899	1,590	120	780
Poland . .	701	1,029	424	279	496	2,929	643	944	328	357	452	2,724	780	943	401
Trinidad .	112	60	2,613	36	241	3,062	110	61	2,690	31	236	3,128	122	63	2,030
British Malay .	622	289	2,712	63	118	3,804	508	230	2,308	62	110	3,218	414	259	1,519
Chile .	809	71	2,813	48	55	3,796	410	64	1,415	32	18	1,939	520	63	1,358
Uruguay . .	766	292	1,661	32	10	2,761	581	180	1,363	23	7	2,154	590	210	1,410
Panama Canal Zone . .	89	26	1,646	11	12	1,784	78	22	1,631	8	7	1,746	80	24	1,792
Iraq . .	145	176	555	36	164	1,076	141	153	530	33	156	1,013	185	182	832
Irish Free State .	1,170	450	132	70	126	1,948	1,110	420	103	65	124	1,822	1,101	416	110
Austria . .	1,158	372	480	171	21	2,202	840	243	425	127	12	1,647	848	276	643
Algeria . .	1,060	370	110	87	80	1,707	930	364	187	81	70	1,632	1,138	377	244
Peru . . .	342	251	696	30	170	1,489	342	328	590	31	165	1,456	428	461	509
Hungary . .	425	514	220	43	23	1,225	435	495	207	41	20	1,198	431	489	341
Greece . .	425	163	601	53	36	1,278	402	166	722	67	32	1,138	393	147	777
Porto Rico .	410	74	946	29	17	1,476	391	59	943	23	16	1,432	449	65	806
Portugal . .	401	316	229	17	31	994	392	315	266	34	38	1,045	432	368	267
Finland . .	486	250	90	56	60	942	442	344	76	63	50	975	511	282	96
French Morocco .	660	207	66	50	49	1,032	726	125	83	38	91	1,063	696	100	77
Others . .	4,677	4,311	13,689	912	899	24,488	5,092	4,211	14,530	891	710	25,434	5,142	4,367	15,114
Total .	561,128	100,600	558,248	41,141	139,157	1,400,274	528,609	103,022	529,405	38,504	128,267	1,327,807	540,988	110,190	554,958

Outside the United States, refinery losses, crude for fuel, and consumption of by-products not included under *Miscellaneous* are yearly estimated as follows:

1931—17,100,000 bbl. making a grand total
1932—20,600,000 „ „ „ „
1933—23,700,000 „ „ „ „
1934—24,000,000 „ „ „ „

VI

Products and Related Fuels

Foreign Dept., Henry L. Doherty & Company

of barrels)

1933			1934						1935					
Lubricants	*Miscellaneous*	*Total*	*Motor fuel*	*Kerosine*	*Gas and fuel oil*	*Lubricants*	*Miscellaneous*	*Total*	*Motor fuel*	*Kerosine*	*Gas and fuel oil*	*Lubricants*	*Miscellaneous*	*Total*
17,066	108,068	866,530	406,000	43,700	329,000	18,600	115,700	913,000	435,300	47,500	346,400	19,900	126,900	976,000
6,121	4,001	95,500	9,840	25,280	52,500	6,800	4,400	98,820	13,565	28,555	56,112	8,150	16,888	123,270
2,937	2,430	65,967	34,500	6,260	25,700	3,020	3,170	72,650	37,454	6,015	25,894	2,692	2,121	74,176
2,019	1,156	38,559	21,400	1,810	12,720	2,100	1,360	39,390	22,200	1,890	14,210	2,110	2,000	42,610
757	1,912	32,813	16,200	1,700	14,200	800	1,600	34,500	16,650	1,750	14,700	830	1,690	35,620
2,001	1,893	23,537	14,200	860	7,500	2,200	1,700	26,460	15,810	1,010	8,850	2,660	2,010	30,340
283	910	20,236	5,480	1,200	12,900	260	970	20,810	5,710	1,180	13,700	320	850	21,760
1,478	470	16,385	6,000	1,200	9,600	1,500	400	18,700	7,122	1,130	13,800	1,602	1,220	24,874
121	2,175	15,735	1,880	600	11,280	140	2,400	16,300	2,100	610	11,400	160	2,580	16,850
195	1,625	13,884	770	1,250	11,400	200	2,000	15,620	790	1,380	11,900	220	1,700	15,990
877	920	13,163	2,150	6,000	3,500	950	930	13,530	2,300	6,200	3,700	950	1,080	14,230
642	240	12,312	3,240	1,200	7,800	640	250	13,130	4,563	1,502	7,600	615	1,660	15,940
544	1,171	10,100	1,520	2,330	5,000	550	1,300	10,700	1,600	2,390	4,900	540	1,480	10,910
336	388	10,280	5,820	1,250	2,900	330	400	10,700	6,600	1,090	2,990	400	500	11,580
24	2,795	8,100	170	30	5,700	30	3,100	9,030	180	25	11,800	30	2,400	14,435
264	93	7,745	900	3,900	2,500	250	100	7,650	1,034	2,666	3,010	281	111	7,102
660	1,410	7,287	700	1,200	3,300	700	1,600	7,500	710	1,380	3,600	610	1,510	7,810
427	137	7,311	3,280	1,460	1,770	390	330	7,230	3,410	1,680	2,110	400	810	8,410
28	380	5,854	590	20	5,200	30	500	6,340	520	22	900	28	5,200	6,670
165	17	5,761	2,280	700	3,100	190	20	6,290	2,400	750	3,200	170	50	6,570
294	116	6,062	3,090	725	1,920	310	135	6,180	3,200	750	1,890	360	420	6,620
174	360	5,283	3,290	200	1,630	190	350	5,660	3,700	150	2,500	220	430	7,000
242	107	4,220	3,000	350	990	320	140	4,800	2,662	248	1,202	397	114	4,623
182	8	4,340	2,160	630	1,580	195	15	4,580	2,290	680	1,802	217	260	5,249
165	69	4,220	430	2,100	1,600	170	80	4,380	560	2,100	2,150	190	140	5,140
41	38	3,537	490	120	3,000	40	30	3,680	560	75	3,800	44	80	4,559
154	147	3,461	2,200	460	700	160	150	3,670	2,800	710	610	210	180	4,510
92	60	3,401	980	270	2,060	90	50	3,450	970	270	2,240	78	90	3,648
102	90	3,463	860	580	1,800	70	80	3,390	900	600	1,900	110	120	3,630
214	30	3,220	1,960	280	800	200	35	3,275	2,050	550	810	240	180	3,830
137	12	3,010	1,780	200	1,100	140	20	3,240	1,892	200	1,140	147	25	3,404
44	59	2,765	920	130	1,800	50	60	2,960	940	130	1,760	50	65	2,945
72	71	2,633	1,680	110	950	70	80	2,890	1,900	120	1,240	75	100	3,435
308	378	2,810	750	920	380	310	360	2,720	815	1,040	370	410	370	3,005
30	210	2,455	120	70	2,200	30	280	2,700	124	73	2,300	32	300	2,829
52	216	2,460	450	260	1,500	50	220	2,480	730	310	1,700	50	200	2,990
43	10	1,994	560	60	1,780	40	10	2,450	680	60	1,500	40	25	2,305
29	11	2,250	660	230	1,500	30	10	2,430	620	220	1,510	35	25	2,410
8	17	1,921	90	30	1,900	10	20	2,050	95	28	2,100	15	30	2,278
39	210	1,448	310	200	1,200	60	240	2,010	390	210	1,780	50	650	3,080
61	150	1,838	1,180	420	160	70	150	1,980	1,060	500	240	65	170	2,035
137	16	1,920	830	270	650	140	20	1,910	981	299	916	141	129	2,403
107	86	1,952	1,000	370	350	100	80	1,900	1,250	400	320	115	100	2,185
32	190	1,620	440	480	520	40	230	1,710	460	580	570	40	220	1,870
58	89	1,408	500	490	480	70	100	1,640	442	445	590	80	90	1,647
41	30	1,388	390	150	900	40	30	1,510	370	150	1,000	55	40	1,615
22	20	1,362	460	70	850	20	30	1,430	480	70	900	30	30	1,510
31	40	1,138	460	380	260	30	40	1,170	520	460	300	35	60	1,375
65	58	1,012	530	290	80	70	60	1,030	682	299	161	64	92	1,298
48	60	981	710	110	90	50	60	1,020	780	110	100	45	100	1,135
984	985	26,592	5,300	4,500	15,600	1,000	1,000	27,400	6,942	5,594	17,527	968	1,838	32,869
40,953	136,134	1,383,223	574,500	117,405	577,900	43,845	146,395	1,460,045	621,863	126,156	617,704	47,429	179,433	1,592,585

consumption of 1,417,374,000 bbl.
,, 1,348,407,000 ,,
,, 1,406,923,000 ,,
,, 1,484,045,000 ,,

Table VII

Production of Natural Gas

In thousands of cubic feet.

Year	U.S.A.	Roumania*	Netherlands East Indies†	U.S.S.R.	Canada	Poland	Mexico	Japan	Italy	Yugo-slavia	Czecho-slovakia	France	United Kingdom‡
1903	..	.	..	..	..	..	..	..	79,656	..	..	..	972
1904	..	..	.	.	..	.	..	..	90,102	..	..	..	775
1905	..	..		..	..	..	..	..	109,193	..	..	..	§
1906	388,843,000	..	.	..	..	.	..	..	202,133	..	..	..	§
1907	406,622,000		.	.	..	.	..	..	201,648	..	..	..	§
1908	402,141,000	.	.	.		.	..	..	237,933	..	..	..	§
1909	480,706,000		.	..	5,600,000	..	..	..	291,983	..	..	..	237
1910	509,155,000		..	..	8,000,000	..	..	..	312,183	..	.	..	262
1911	512,993,000		.	..	11,644,000	..	..	..	318,575	..	.	..	221
1912	562,203,000		.		15,286,803	.	..		240,141	.	.	..	161
1913	581,898,000	3,669,042	..		20,477,838		.	50,000†	212,419	..	..	..	87
1914	591,867,000	4,062,252	..	.	21,692,504	.	..	56,606	209,064	..	..	..	87
1915	628,579,000	3,751,719		..	20,124,162		.	50,166	205,250	..	..	..	87
1916	753,170,000	3,282,683	4,054,893	.	25,467,458	..	..	86,940	202,424	..	..	..	85
1917	795,110,000	1,394,434	8,905,282	..	27,408,940	..	..	157,266	236,609	.	..	..	85
1918	721,001,000	1,564,393	8,751,325		20,140,309		..	159,646	237,775	..	.	..	85
1919	745,916,000	5,094,628	6,506,612	.	19,937,769		.	183,866	309,287	..	..	..	90
1920	798,210,000	6,023,391	8,398,752		16,845,518	14,303,611	.	236,801	269,044	..	..	.	95
1921	662,052,000	6,374,634	3,924,544	.	14,077,601	14,259,284	.	205,298	279,038		..	.	100
1922	762,546,000	8,832,020	4,585,858		14,682,651	14,196,550	.	1,124,595	234,949		..	.	100
1923	1,006,976,000	10,139,360	9,926,303		15,960,583	13,780,859	.	925,650	241,942	..	..	..	100
1924	1,141,521,000	12,795,223	12,615,972	.	14,881,336	15,465,869	..	712,043	236,609	..	.	..	100
1925	1,188,571,000	13,060,119	18,338,850		16,902,897	18,893,736	.	819,497	244,866	..	14,568	..	100
1926	1,313,019,000	13,304,994	16,604,329	7,659,144	19,208,209	16,999,379	..	788,109	209,770	..	11,512	..	100
1927	1,445,428,000	15,433,908	16,302,975	8,651,420	21,376,797	16,037,828		993,202	206,507	21,328	9,658	.	100
1928	1,568,139,000	21,648,805	21,337,883	12,209,850	22,582,586	16,226,656	.	970,045	225,917	32,857	9,939	11,936	7,000
1929	1,917,693,000	28,484,879	23,955,907	13,045,500	28,378,462	16,502,076	.	‖	247,144	39,749	60,042	11,544	7,000
1930	1,943,421,000	42,594,019	24,040,769	‖	29,376,919	17,180,686	.	‖	307,186	188,765	109,149	10,846	7,000
1931	1,686,436,000	48,842,910	30,369,648	34,074,000	25,874,723	13,889,841	9,326,495	2,705,675	427,777	225,182	34,830	10,787	7,000
1932	1,555,990,000	51,419,625	40,112,433	39,721,500	23,420,174	15,432,568	9,068,721	1,810,449	454,835	‖	31,806	‖	7,000
1933	1,555,474,000	56,280,844	45,226,729	48,166,800	23,138,103	16,322,818	11,046,923	1,554,900	489,910	33,211	40,930	8,652	7,000
1934	1,770,721,000	64,061,036	47,484,926	62,300,000‡	23,164,324	16,560,688	12,254,000	1,664,083	529,394	31,812	42,569	8,970	7,000
1935	1,875,000,000	67,593,000	47,976,429	89,000,000‡	24,910,786	17,163,000	‖	‖	436,291	49,480	‖	‖	7,000

* Consumption. † 1 metric ton = 44·5 M. cu. ft. ‡ Estimated. § Not stated. ‖ Not available.

Table VIII

Production of Oil Shale

In tons.

Year	United Kingdom	Estonia	France*	Spain	Italy†	Tasmania	New South Wales	New Zealand	U.S.S.R.	Germany (Bavaria)	Austria‡	U.S.A.	Manchukuo
1901	2,354,356	..	245,713	..	..	..	54,744	12,048	..	..	..	..	..
1902	2,107,534	..	254,216	..	..	..	62,880	2,338	..	..	..	..	..
1903	2,009,602	..	239,453	..	..	..	34,776	36	..	..	..	..	..
1904	2,333,062	..	223,590	..	..	..	37,871	..	..	..	..	..	..
1905	2,496,785	..	188,485	..	..	..	38,226	..	..	..	..	..	..
1906	2,546,552	..	193,274	..	..	..	32,446	..	..	..	..	..	..
1907	2,690,028	..	174,278	..	..	..	47,331	..	..	..	..	..	..
1908	2,892,039	..	168,455	..	..	..	46,303	1	..	..	..	..	..
1909	2,967,057	..	166,385	..	..	..	48,718	..	..	..	515	..	..
1910	3,130,280	..	167,088	..	..	..	68,293	..	..	..	548	..	..
1911	3,116,803	..	167,017	..	..	..	75,104	..	..	..	1,243	..	..
1912	3,184,826	..	602,187	..	..	..	86,018	..	..	..	1,189	..	..
1913	3,280,143	..	319,472	..	2,600	..	16,985	..	..	..	922	..	..
1914	3,268,666	..	128,487	..	1,564	..	50,049	..	..	..	297	..	..
1915	2,998,652	..	54,238	..	4,665	..	15,474	..	..	..	39	..	..
1916	3,009,232	..	82,747	..	4,503	1,266	17,425	..	..	..	..	..	..
1917	3,117,658	..	102,930	..	19,551	..	31,661	..	..	..	..	..	..
1918	3,080,867	16	92,622	9,400	21,469	..	32,395	..	..	..	..	..	..
1919	2,763,875	9,484	48,337	5,438	11,161	600	25,954	..	4,461	..	987	..	..
1920	2,842,582	45,417	68,244	§	16,737	140	21,000	..	27,900	..	1,077	..	..
1921	1,866,896	93,517	63,653	§	4,782	868	32,490	..	18,700	373	1,140	..	..
1922	2,603,996	136,800	60,037	§	5,388	40	23,467	..	18,210	32	704	..	..
1923	2,860,633	181,161	61,143	§	5,571	1,101	1,210	..	29,310‖	1,183	371	9,300	..
1924	2,857,103	239,876	69,827	§	3,382	1,575	642	..	11,500‖	522	367	21,200	..
1925	2,464,829	283,474	66,067	66,434	5,362	820	..	..	1,112‖	394	642	§	..
1926	1,959,795	432,652	68,097	§	10,039	2,127	..	..	1,841‖	10	465	5,500	..
1927	2,047,263	391,338	86,100	53,480	11,899	3,150	..	..	9,285‖	472	445	7,400	..
1928	2,038,114	439,169	75,830	53,256	7,271	2,595	..	..	553‖	660	649	1,897	..
1929	2,023,609	509,476	76,543	54,033	8,101	4,300	..	..	§	593	660	1,740	..
1930	2,020,510	490,090	81,197	54,276	10,923	5,430	346	..	§	535	379	.	..
1931	1,732,746	393,185	73,364	54,733	9,236	1,400	2,130	..	§	411	327	..	1,225,429
1932	1,368,596	493,880	86,582	63,119	7,163	1,100	2,690	..	§	394	316	..	1,390,245
1933	1,396,988	492,073	89,563	59,493	10,875	3,400	3,401	..	§	552	213	..	§
1934	1,400,775	579,656	100,724	37,186	4,642	§	3,476	..	§	888	405	..	§
1935	1,408,371	473,608	§	§	12,440	§	30	..	§	716	345	..	§

* Including some Boghead coal. † Including ichthyolic shale. ‡ Ichthyolic shale. § Not available. ‖ Year ended 30 September.

TABLE IX

Production of Natural Asphalt and Asphalt Rock

In tons.

Year	U.S.A.	Italy	Trinidad Asphalt	Trinidad Manjak	France	Germany	Switzerland*	Venezuela*	Spain	Cuba*	Netherlands East Indies	Poland†	Czechoslovakia	Yugoslavia	Barbados‡	U.S.S.R.	Roumania	Albania	Peru	Mexico	Japan	Austria	Greece	Hungary
1901	56,372	102,467	..	..	..	88,770	..	..	3,894	..	..	2,664	..	..	1,044	26,202	..	..	..	..	..	..	..	2,833
1902	75,568	63,230	..	..	..	86,980	..	..	6,202	..	..	2,613	..	..	868	12,165	..	..	..	..	..	..	..	2,730
1903	49,170	88,274	182,342	880	..	86,070	..	14,337	6.178	4,714	..	2.804	..	..	650	25,173	..	..	..	..	351	..	..	2.384
1904	57,295	110,133	133,041	4,534	..	90,290	..	35,653	3,702	8,785	..	3,037	..	..	501	§	..	..	..	..	535	..	..	2,186
1905	65,090	105,324	100,578	1,615	..	101,380	..	30,190	5,635	9,982	..	2,910	..	..	929	20,886	..	..	..	..	101	..	..	170
1906	65,233	129,265	132,417	2,273	193,221	115,560	..	19,763	7,670	5,104	..	2,655	..	..	782	10,960	..	..	..	1,367	38	5,448	..	4,046
1907	76,707	159,088	150,168	2,114	174,231	124,650	..	33,614	8,089	4,974	..	2,468	..	..	693	12,607	..	..	..	4,415	575	6,263	..	3,858
1908	70,148	131,977	125,994	1,790	168,410	87,600	..	40,130	12,178	6,138	..	2,551	..	..	430	21,685	..	..	..	5,189	2,366	6,185	..	4,743
1909	88,447	109,777	141,924‖	2,395‖	166,340	76.310	..	37,292	5.200	10,626	..	2,082	..	..	342	56	..	..	..	5,385	4,120	5,008	..	4,974
1910	88,297	160,130	138,244‖	1,910‖	167,042	79,925	..	33,306	7,672	2,072	..	2,137	..	..	174	23,546	..	..	..	2,804	469	3.183	..	4,915
1911	77,745	185,702	184,753‖	1,570‖	166,972	80,610	..	36,049	3,682	3,248	..	1.910	..	..	164	..	..	..	..	7,957	1,240	3,622	..	3,800
1912	84.970	179,073	210,047‖	1,251‖	306,840	94,600	..	55,622	5,302	15,410	..	1,656	..	..	158	..	..	..	..	30,010	2,860	5,823	..	4,390
1913	82,682	168,347	226,634‖	581‖	40,300	103,800	49,573	79,925	5,494	1,562	..	1,331	..	..	116	..	..	..	..	..	2,225	2,977	..	2,976
1914	71,329	117,927	110,289‖	729‖	34,984	80,500	32,329	56,432	5,672	865	..	797	..	..	70	..	..	..	..	..	1,975	2,592	..	3,245
1915	67,635	46,884	5,511¶	503¶	11,519	31,900	16,950	24,956	4,448	434	..	56	..	..	64	..	..	..	.	382,186	1,945	40	..	2,122
1916	87,925	16,559	128,780	..	14,150	31,000	20,182	46,442	7,198	481	..	222	..	..	66	..	..	..	11,890	..	2.266	148	..	..
1917	72,861	8,506	131,483	434	11,874	12,300	14,530	52,139	1,788	465	..	323	..	..	76	..	..	..	8,003	..	3,813	254	..	..
1918	53,602	21,950	71,223	171	9,942	8,300	1,760	45.706	3,633	443	..	..	..	..	54	..	..	..	14,680	..	2,954	..	..	..
1919	78,822	76,746	93,806	208	17,826	12,400	8,748	45,176	4,491	630	..	294	..	..	38	..	738	..	13,811	..	6,570	987	..	..
1920	177,231	104,928	141,100	134	24,622	31,400	13,825	23,075	4,154	2,995	..	362	..	..	91	..	1,039	..	16.891	..	6,823	1,078	1,670	..
1921	264,653	91.746	119,729	..	38,959	28,900	17,202	47,710	3,476	337	..	256	..	..	109	..	13,859	..	11,647	..	6,831	1,575	478	..
1922	292,668	66,804	182,655	..	47,698	53,741	21,691	33,436	5,838	107	..	423	..	..	131	..	12,807	..	8,690	..	275	..	403	..
1923	357,360	148,717	221,347	..	39,427	45,501	19,590	32,785	3,873	2,064	..	506	..	..	180	..	21,614	..	§	..	..	..	1,279	..
1924	502,137	183,582	223,867	..	50,638	56,473	32,626	68,769	5,388	3,584	..	720	..	..	70	..	19,414	..	2,665	..	..	..	4,932	..
1925	522,212	268,603	201,107	..	48,709	63,805	35,282	33,138	5,490	1,509	45	728	..	..	30	..	15,456	..	1,051	..	..	..	5,171	..
1926	638,584	307,850	237,300	..	52,000	60,003	27,747	50,738	5,764	23,785	153	712	..	84	107	27,400**	24.498	..	679	..	..	..	396	..
1927	749,179	356,945	242,131	..	47,764	115,975	36,136	109,881	4,443	24,650	1,319	724	..	140	45	45,313**	30,277	..	§	..	..	..	285	..
1928	721,338	238,473	195,980	..	63,262	155,828	20,984	47,979	7,613	10,957	1,033	755	586	527	59	25,958**	8,735	2,241	966	..	..	..	3,123	..
1929	717,916	216,116	219,603	..	45,082	143.046	19,693	27,474	8,860	5,219	14,793	822	1,755	62	52	§	..	2,472	935	..	..	..	1,177	..
1930	627,510	220,496	137,859	..	69,160	115,311	16,849	§	9,330	20,698	12,696	887	658	237	10	§	..	§	§	..	..	..	1,524	..
1931	421,719	186,786	123,138	..	56,822	68,270	15.089	§	5,054	9,536	2,356	324	995	124	9	§	..	§	§	..	..	..	..	..
1932	303,588	126,278	107,457	..	47,018	32,800	6.831	6,626	6,200	5,218	837	639	136	125	..	§	..	§	§	..	..	..	..	..
1933	279,634	49,162	111,337	..	57,783	43,168	5,286	§	6.722	4,896	6,667	362	335	141	24	§	..	§	§	..	..	..	..	..
1934	393,618	133,373	92,829	..	37,754	64,242	6,163	§	6,421	§	6,221	154	..	115	27	§	.	§	§	§	..	..	..	..
1935	310,175	146,766	134,578	..	36,122	71,180	4,900	§	§	§	4,684	353	§	121	27	§	.	§	§	300,676	..	..	..	..

* Exports. † Ozokerite. ‡ Manjak exports. § Figures not available. ‖ Year ended 31 March of following year. ¶ Nine months to 31 December. ** Year ended September 30.

SECTION 3

ORIGIN OF PETROLEUM

THE ORIGIN OF PETROLEUM

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Introduction

FEW subjects of scientific interest have excited more speculation than the origin of petroleum, and few are burdened with a heavier load of literature. Geologist, chemist, biologist, and physicist have each their quota of evidence to contribute and their own particular viewpoint to perpetuate. Yet, as is so often the case where the sciences overlap, the progress of discovery has been slow, for research has lacked the co-operation between the sciences which is essential to success.

Yet it must not be imagined that this is only a subject of purely scientific interest. Its elucidation is of vital importance in the task of searching for new oilfields. The more obvious areas for drilling have now been tested, and the march of discovery renders the task of finding new oilfields ever more difficult. Untested areas have to be reviewed in the light of new ideas, and developed areas are drilled to greater depths to test deeper geological horizons. In this intensive search it is essential that the geologist should have a proper conception of the natural history of the substance for which he is searching. He must know in particular the environment in which petroleum is formed, so that he may utilize his stratigraphical studies to concentrate attention on areas which have been associated in the past with such conditions.

It must, however, be conceded that the origin of petroleum is a problem of unusual difficulty. Unlike coal, which can be examined in detail and its physical components differentiated under the microscope, oil gives no such evidence to the scientist. Furthermore, its fluidity enables it to pass from rock to rock so that often it is not even possible to state with any certainty the given rock type in which a particular petroleum was formed. This power of migration is one of the greatest difficulties with which the oil geologist has to contend, and there are only a few oilfields in which the source rocks can be identified with any certainty.

One further difficulty arises from the fact that the term petroleum is sometimes used vaguely to cover materials which, though chemically related, are not part of the same family. Thus natural gas is a true petroleum derivative and consists essentially of methane, but all natural occurrences of methane are not natural gas, and even a cursory study will show that methane has originated in several different ways in nature. Most of these have probably no significance from the point of view of the origin of petroleum, but all have been put forward at some time or other as significant evidence. Another instance may be given in the case of the so-called oil shales and bituminous sandstones. The former substance is not a shale containing oil and is probably not related to petroleum in any way; it is merely a material from which, like cannel coal, an oil can be formed by destructive distillation. The term 'bituminous' is also often used by the geologist as a synonym for 'carbonaceous', and may not therefore have any reference to petroleum. These examples of unfortunate terminology have added considerably to the confusion by their inclusion as evidence by the unwary.

There can be little doubt that hydrocarbons have originated in many different ways in the earth's crust, but this conclusion does not necessarily apply to the accumulations which are of commercial importance. The present problem is limited to the latter, and therefore the primary evidence must be sought in the conditions in which the large accumulations are developed. The chemist in particular is prone to regard the chemical nature of the substance as its primary characteristic and has complicated the issue by suggesting so many ways in which petroleum, or rather hydrocarbons, could be produced given an unrestricted choice as to the materials available and the conditions to which they had been subjected. Fortunately neither of these two factors are unrestricted, but as their study does not come within the province of the chemist, it can readily be understood that he has not always felt himself tied by their limitations. The so-called 'Inorganic Theories' all come within this category, and none of them would ever have been entertained if due weight had been given to the geological evidence. On the other hand, the geologist has often gone astray with unfortunate results when wandering beyond his own field of inquiry to a discussion of the processes by which petroleum could be formed.

It would seem logical to assume that the first steps in this inquiry should be taken by the geologist. It is he who has to study the conditions in which petroleum is found and must trace its history from the earliest stages to the condition of a large accumulation. The latter is contained within the rocks of the earth's crust, and it is the geologist's function to study these rocks and to consider the succession of events which brought them into being and their history after formation. The history of the oil formed a part of this broader history, and among the important questions which the geologist must decide are the following:

(*a*) The conditions of sedimentation which have given rise to oil-bearing rocks.

(*b*) The basic material from which it may be presumed the oil has originated.

(*c*) The limiting conditions of temperature and pressure to which these rocks have been subjected since their formation.

These will act as limiting factors to all chemical and physical theories of oil formation.

The answers to these questions do not give a complete theory of the origin of petroleum, but they narrow the field of inquiry. There is still the important question of the precise processes by which the petroleum is produced and the time needed for the transformation. On these matters the chemist and the biochemist can claim their right to enter the discussion, and the geologist's contribution can only be based on such studies as may condemn or support chemical reasoning.

It is not the purpose of the present article to deal in detail with the geological evidence on the origin of petroleum. It will be sufficient to give the broad conclusions which can be drawn from this mass of evidence and deal only in detail with such matters as are still in doubt.

The following are some of the general conclusions with

regard to the geological occurrence of oil with which practically all oil geologists will concur.

1. Petroleum as a solid, liquid, or gas is of widespread occurrence in the earth's crust, particularly in sediments. As an accumulation of commercial importance it is much less common and is restricted to areas of considerable sedimentation.

2. The oil and gas are found in porous rocks such as sands, dolomites, or limestones. These rocks usually form part of a thicker sedimentary series in which clays, marls, or limestones predominate. It must be assumed that the oil and gas have been formed from organic matter in these sedimentary suites, and the clays and limestones are the probable source rocks.

3. Porous rocks such as sands constitute the reservoir rocks because it is only from such permeable formations that the oil can be extracted in commercial quantities. In most cases the clays and limestones also contain oil, but it is too diffuse or too tightly held to be extracted profitably.

4. In particular oilfield regions the commercial oil-pools are clearly restricted to certain geological formations. Within these formations there are certain clays or limestones which have been claimed with good reason to be the source rocks. This identification is not always possible because of the migratory powers of petroleum, but where the evidence is clear the identification can be accepted with considerable confidence.

5. The oil-bearing rocks of most oilfields are marine, and the oil usually rests on salt-water which is believed to be derived from the original sea-water in which the sediments were laid down. There are, however, some oilfields in terrestrial formations in which the oil may have been produced in such rocks or may have migrated from other sources. The great preponderance of marine rocks in the known oilfields leaves no doubt that the source rocks from which the oil has been produced were normally laid down in a marine environment. The foregoing is a statement of fact and is not meant to assert that oil could not be formed in fresh-water sediments. The exceptions referred to above may represent such cases, though many of them seem to be migratory oils.

6. The sediments in which the oils occur show very little evidence of having been subjected to either abnormal heat or pressure. Some of them are folded, occasionally even highly folded, but there are other regions of prolific oil-pools which have not been subjected to any folding movements whatsoever, whilst nearly all oilfields have escaped any type of regional or local metamorphism. Occasionally an individual pool has suffered local effects from igneous activity, but the only thermal influences on the sediments that can be ascribed to the majority of the oilfield strata is the increase in temperature due to the overlying load of sediments. In most cases this rise in temperature could not have been more than 100° C., for the temperature gradients in such rocks are low and the cover was usually not greater than 20,000 ft., though there are cases of exceptional overburden.

General Theories of the Origin of Petroleum

Inorganic Theories.

So many theories have been put forward for the origin of petroleum that it would be invidious to select any particular ones as representative. More particularly is this true of the so-called inorganic theories which visualize the origin of oil and natural gas as a large-scale, simple laboratory reaction within the earth's crust. Mendeléeff, for instance, considered that it was essentially a reaction between descending waters and subterranean metallic carbides [14], whilst Berthelot thought that it might be due to water charged with carbon dioxide coming into contact with metallic sodium [5, 1866]. Apart altogether from the intrinsic merits or interest of such theories they all fail to satisfy the fundamental requirement that the origin of petroleum in large quantities is bound up with the history of particular sediments.

The same reasoning may be applied to the so-called volcanic theory, which is a modification of the normal inorganic theories. This visualizes petroleum as one further example of the ultimate phase of vulcanicity. It is true that in certain oilfields, as, for instance, Mexico, there are some incompletely explained examples of association between igneous rocks and oil deposits, but these appear to be cases of favourable conditions for accumulation rather than of origin, and they are so exceptional that they have attracted more than their share of attention. Furthermore, the argument that there is parallelism between the world's oilfields and the distribution of volcanoes is true only in part and is completely falsified by the Palaeozoic oilfields of the United States. This parallelism is more true of the Tertiary fields, and is undoubtedly due to the fact that vulcanism and the occurrence of petroleum are both independently related to the zones of Tertiary marine sedimentation which were later affected by crustal disturbances. Taken as a whole, the study of oilfield regions indicates clearly that they are not normally associated with any phase of igneous activity.

Organic Theories.

The synopsis of the geological factors connected with the origin of oil which was given above leaves no doubt that it must be formed from organic matter deposited in the sediments with which it is associated. Although there may be general agreement on this point, there are considerable divergences of opinion on other matters which are of equal importance. It must not be forgotten that the source of the organic matter is but the first stage in the process. Other considerations include the environment in which such source sediments are laid down; the factors which have changed the organic material into petroleum, and the time at which such changes have taken place, i.e. whether oil originates in the sediments or is produced at a later stage when the sediments have become rocks. All of these questions must be considered in a complete theory, and there is clearly room for diversity of opinion among authors who may be in complete agreement on the question of the original source material.

Source Material.

There has been a tendency for a division of thought into two broad groups: those who believe in the origin of petroleum from terrestrial vegetation, and those who consider animal matter of marine origin to be the probable source. Such a grouping does not cover the whole field, for in such vegetal substances as marine algae and diatoms we have obvious contributing elements which may be of great importance. It would perhaps have been to better purpose had the battle been fought on the question whether oil originated from terrestrial or marine matter, for that would have thrown light on the environment in which source sediments are laid down, a much more important question. Furthermore, it may be questioned whether nature's processes are particularly concerned with whether

a material be animal or vegetable, though the question whether it consists of cellulose, fat, or protein may be of fundamental importance. It is the chemical nature of the materials, and in particular their decomposition products after partial putrefaction, which are of primary importance. This and the environment of deposition are clearly the two main considerations.

There has been one field in which controversy was bound to occur, the fundamental relationship between coal and oil. Are these two substances in any way related? Have they been produced from analogous materials, and are their differences due to variations in treatment of the original materials? Or, on the other hand, are they related in the sense that they are produced from different materials, but have undergone a parallel series of changes after entombment? Both points of view have been championed vigorously, the first by E. H. Cunningham Craig [6, 1912] and the second by David White [26, 1935].

The arguments for the supposed relationship between coal and oil may be briefly summarized as follows:

(*a*) There is a general geographical and geological relationship between coal and oil.

(*b*) In certain instances it has been claimed that coal or lignite can be proved to pass laterally into oil-bearing strata.

(*c*) The decomposition of vegetable matter in water produces methane which is chemically identical with the basic constituent of natural gas.

(*d*) The destructive distillation of coal, lignite, and peat gives substances closely akin to petroleum. The hydrogenation of coal would be a further instance.

(*e*) Coal and oil have been claimed to have undergone parallel changes in certain regions, particularly in the Appalachian oilfields.

All of these comparisons, save the last, bear directly on the source material of petroleum, so they may be considered in detail. The last point is of greater importance when it comes to the consideration of the forces which produce petroleum and will be considered in that section.

(*a*) The geographical relationships of coal and oil can have little bearing upon the problem, but a geological association would be of fundamental importance. A review of the world's oilfields, however, shows very little evidence to support this view when due allowance is made for the fact that both materials occur in sediments, and oil, being of migratory habit, can readily pass into neighbouring strata. Coal and oil are found in the same formations in Kansas, Venezuela, Assam, Borneo, and Roumania, but the majority of oilfield measures do not contain coal. Indeed, oilfield strata are normally marine in contrast to the brackish or fresh-water conditions associated with most coals.

Two examples have been freely cited to support the contention of a close geological association of coal and oil, Pennsylvania and Trinidad. Both are unfortunate examples, for in each the coal and oil occur in different strata and the line of demarcation is clear cut. In Pennsylvania an upper coal-bearing series lies disconformably on an underlying oil-bearing formation. The break between the two formations is clearly defined, and there was a considerable period of erosion between them. There are no coals in the underlying series and no oil in the overlying beds. A little gas has migrated above the plane of unconformity, but this is hardly to be wondered at; indeed, the outstanding feature is the sharpness of the break between the oil and the coal series in spite of the migratory habits of oil. It has been argued that in this case the lower series under a greater cover has changed to oil, whereas the upper formations have retained their organic matter as coal. This argument is, however, not tenable, for the line of demarcation follows the plane of unconformity and not the zone of equal cover.

In Trinidad the lignitic strata of the Upper Miocene occur as a fresh-water formation which is clearly separated from the underlying marine oil-bearing series except for a few cases in which migration has occurred. The source of the oil in the lower series is not satisfactorily settled, but there can be no doubt that it did not originate in the upper lignitic series.

The problem must also be looked at from the point of view of the regional and stratigraphical distribution of coal as well as that of oil. Such studies leave no doubt that the two substances are completely independent of each other.

(*b*) The cases of a supposed lateral variation of coal or lignite into oil within a limited distance are few. Wall described tree-trunks submerged in the pitch of the Pitch Lake in Trinidad in which he claimed that the bitumen was derived from the decomposed cell structure of the wood [22, 1860]. There can, however, be no doubt that he was merely dealing with cases of semi-decomposed wood tissue which had become impregnated with bitumen from the surrounding pitch. E. H. Cunningham Craig describes an example on the coast of Trinidad between Point Fortin and Cedros [7, 1912]. The formations he was considering belong entirely to the lignitic series, and he was mistaken in his view that the porcellanite, which he claimed was the lateral equivalent of a lignite, had been an oil-bearing clay. It is, of course, freely admitted that a coal-bearing series can pass laterally into an oil-bearing series with a change in facies from deltaic to marine, but such regional changes do not bear on the question at issue, for the source of the organic material may be quite different.

(*c*) The decomposition of vegetable material to form marsh gas is the strongest material link between oil and coal. It must, however, not be pressed too far. The gas associated with vegetable material and coal contains only methane and none of the higher molecular weight hydrocarbons, whereas 'natural gas' often contains ethane, propane, butane, &c., in considerable quantities.

(*d*) The destructive distillation of coal, peat, &c., gives liquid oils and gas which, while differing from petroleum particularly in the percentage of their unsaturated constituents, are probably no more distinct than are the variations to be noted between different types of petroleum. Such differences also cannot be stressed unduly, for the heat treatment to which these oils have been subjected may be a partial cause of these unsaturated hydrocarbons. Apart altogether from such questions, the real point is how far such comparisons affect the issue. In this case the significance of such distillation products can be very little, for it was shown long ago by Warren and Storrer [23, 1867], and later by Engler [8, 1888–9], that animal fats could produce oils on destructive distillation which were much more akin to petroleum products.

Hydrogenation as practised in the formation of petrol from coal requires high temperatures and pressures and a supply of hydrogen. It is very doubtful indeed whether these conditions occur in nature in oilfield strata, and though some suggestion of alterations in oils due to hydrogenation have been put forward, they are quite unsubstantiated.

The results of the foregoing considerations leave little

positive evidence in favour of a genetic connexion between oil and coal. The geological environment favourable to the formation of each is shown to be completely different: coal is essentially a terrestrial deposit, whilst oil is normally produced in rocks formed in a marine environment. This does not prove that each may not have been produced from the same organic matter, but it makes it exceedingly unlikely, and though both materials are of organic origin it seems probable that this is about the full extent of their connexion.

Owing to the migratory habits of petroleum it is not always possible to assert conclusively that a particular formation is the source rock from which the oil was obtained in a particular region. There are, however, some areas where the source rock can be identified with considerable probability. Sterry Hunt [11] identified the Trenton Limestone as the source rock for the oils which were found in it, basing his argument on the compactness of this formation and the impossibility of oil moving for any considerable distance through it.

Arnold and Anderson claimed that the Monterey Shales of California were the source rocks of most of the oil in that area [2, 1910]. They drew attention to the abundance of diatoms in that formation, and suggested that the oil had been derived from these organisms. The oil in California has perhaps several zones of origin, but the consensus of opinion still supports the Monterey Shales as the most important source rock. Taff has suggested that both diatoms and Foraminifera contributed to the source material and that the chemical nature of the oil so produced varied with the type of organic matter [17, 1934]. In Poland the main oil sands are so closely associated with the Menelite Shales that it was inevitable that these shales would be considered as the rocks from which the oil had been derived. Such cases can be considered as representative, and in each case the source rock is marine. It is composed of clay, marl, or limestone, and in some cases the rocks are obviously rich in organic remains, but in others, particularly the dark clays, the evidence of organisms is not by any means striking.

It might be argued that if oil is formed in marine sediments, a study of the latter ought to bring to light examples of oil in process of formation. This, of course, assumes that the oil is formed immediately the deposit is laid down and not as a later process when the sediment becomes a rock. Various claims have been made of oil or hydrocarbons being produced on the sea floor, but none of these can be accepted without reserve. One of the main difficulties is that it is almost impossible to eliminate the chances of contamination by seepage of oil from the basement of the sea floor, and the cases cited by the Hungarian expedition to the Levant [15, 1901], and by Wade in the Red Sea [21, 1914], are all suspect on this account. Krämer and Spilker described the formation of a wax in the sediments of the Gulf of Stettin which they compared with ozokerite, the hydrocarbon wax of the Boryslaw oilfield [12, 1900, 1902]. This identification has, however, been challenged by Potonié, who considers that their material was merely semi-decomposed organic matter analogous to sapropel [16, 1904].

Trask and Wu have undertaken an extensive examination of marine sediments both to study their organic content and also to see if there is any evidence of oil formation contemporaneous with deposition. So far as the latter question is concerned they conclude that there is no evidence to support such contemporaneous oil formation [20, 1930]. Trask's studies of organic matter in marine deposits need not be referred to in detail here, for they form the subject of a separate contribution. It is sufficient to point out that he finds appreciable quantities of organic matter in sediments, particularly along the flanks of submarine basins. These organic mixtures contain little of the original fats, protein, and carbohydrates of the organic matter, but correspond rather to complex residual substances, the ultimate result of bacteriological decay.

This conception of a preliminary stage of decomposition or putrefaction is by no means new. It was postulated by Engler in his theory of oil formation, first as a means of eliminating nitrogen, and secondly as a preparatory stage of the break-down of the fatty matter [9, 1909].

It is agreed that some initial putrefactive process is incidental to the deposition of all organic matter, and such a conception seems eminently reasonable. We are not concerned so much with the original composition of the organic matter as with its composition after such decomposition has taken place. The general tendency of Trask's investigations appears to prove that all such organic matter tends to become enriched in carbon and hydrogen by the preferential elimination of oxygen and nitrogen. This subject is treated fully in Trask's contribution on 'Petroleum Source Beds', and the reader is referred for further details to this contribution.

Environment of Deposition.

It is sometimes claimed as an inherent weakness in the marine origin theory that the examination of modern sediments has failed to discover any which are sufficiently rich to enable them to become the sources of petroleum. This claim is, however, based on a misconception. The petroleum found in a reservoir rock forms only a small percentage of the total volume of the reservoir, for most oil reservoirs contain large water-saturated sections. Furthermore, the reservoir rock is usually but a small percentage of the total volume of source rock, so that the volume of oil to be accounted for is only a small percentage of the total source rock. There is no need, therefore, to consider that petroleum source sediments need be abnormally rich in organic matter, and the quantities of such material that have been discovered in sediments of suitable environment are adequate for our purpose. There are, it is true, some instances of abnormally rich marine sediments such as those which have been studied in the Black Sea by Archangelski [1, 1927]. Here the conditions for preservation of organic matter appear to be particularly favourable, and the organic content rises to as much as 18%. The writer is, however, inclined to the view that sediments of such abnormal richness are probably unnecessary. Petroleum formation is a normal, not an abnormal, process in the history of marine sediments, and it is therefore more likely that it requires an environment which, while it involves certain essentials, does not involve features which are only rarely attained.

That rapid oxidation is the normal accompaniment of shallow-water marine deposition is well known, and organic matter laid down in such conditions will be rapidly oxidized and lost. There are, however, certain cases in shallow-water sediments where the sediments contain no free oxygen, and in the deeper parts of the sea this is the normal condition. McKenzie Taylor has shown that some clays, when subjected to base exchange, can become so impervious that even in shallow water they produce an anaerobic environment [18, 1928]. In the basal areas of

the sea floor it is probable that the lack of convection currents and the resultant stagnation of the water leads to the bottom waters being exhausted of their oxygen and the environment becoming anaerobic. Furthermore, the broad areas of the sea floor which are covered with blue muds, a type of deposit typical of an anaerobic environment, indicate how commonly the conditions of the sea floor are of this type.

It is not, however, sufficient that the conditions of deposition be anaerobic to satisfy all the requirements for a source sediment. There must be an adequate supply of organic matter to form the basis of the material from which the petroleum will ultimately be derived. The conditions must be favourable to the continued development of organic matter in the water, and probably imply favourable conditions for the growth of phytoplankton. The marine areas adjoining the main continents or close to the zones of oceanic islands provide such an environment, but in parts of these zones the conditions for the preservation of the organic matter would be unfavourable. However, on the edges of the main basins and in the dominant basins of the submarine platforms there would be conditions favourable to the development of life and to the preservation of the organic matter in the sediments. It therefore seems probable that petroleum-source sediments were laid down in marine basins and at no great distance from land, a condition which is in agreement with the palaeogeography of oil-bearing rocks in most of our oilfields. It is also probable that the sedimentation of the organic matter is greatly helped by the muddy sediments in the water, but the incidence of such conditions has not been specially studied.

The importance of bacteria in the special decomposition processes has been emphasized in the case of other substances [4, 1926]. The formation of iron sulphide in the black muds is apparently due to the decomposition of the sulphates in the sea-water—the formation of free hydrogen sulphide which reacts with iron hydroxide in the sediments to form iron sulphide. This seems to be but one instance of the importance of bacterial control of the conditions in such sedimentary environments, and under such conditions the decay of the organic matter is probably mainly controlled by bacteria and it is converted into organic acids or their derived salts. The large volume of salt-water present would probably inhibit the production of toxic conditions in the sea-bottom, so that bacterial decay would go on. A further preventive to such toxic conditions would be the decomposition of protein to form alkaline solutions [24, 1937], and the inwelling of waters of slightly different salinity which would cause base exchange in the sediments in which the organic decomposition was taking place.

The Transformation of Organic Matter into Petroleum.

The ultimate formation of petroleum from the decomposition products of organic matter in the sediments is the most elusive problem in the origin of oil. There are two broad schools of thought into which the various theories can be divided. These two schools postulate, on the one hand, a process of temperature or pressure metamorphism, and, on the other, decomposition by bacteria. Whatever compromises may be made regarding the type of organic matter involved, there can be no compromise between these two mutually antagonistic ideas.

The theory of metamorphism may be regarded perhaps as the orthodox school in so far as it has been held ever since the origin of petroleum has been discussed, and is based on a wealth of chemical data. The fundamental idea is that the organic matter, after an initial process of putrefaction, to eliminate the nitrogenous material, is entombed in the sediment, and that the rise in temperature involved in such burial produces a slow process of chemical distillation involving long geological periods. It is claimed that high temperatures will not be needed; the same processes which take only a few hours in a retort will take place at much lower temperatures if given sufficient time. Thus Maier and Zimmerly claim there would be a 1% conversion of the organic matter in $8{\cdot}4\times10^5$ years at a temperature of 100° C. [13].

It is, however, not necessarily true that a reaction which takes place in the laboratory at 275–325° C. will take place, though at a much slower rate, at temperatures around 100° C. Before such claims can be made the rate of the reaction must be studied, particularly at the lower end of the temperature scale, for most reactions of this nature tend to occur only within a certain range of temperatures. Obviously the results will vary with the substance used, but in some experiments on a typical torbanitic cannel which the author has investigated it was clearly shown that the reaction velocities did not diminish with temperatures below 250° C. in accordance with theoretical calculations, but at a rapidly increasing rate showing an approach to virtual stagnation at about 220° C. This would be in accordance with many other similar endothermic chemical reactions which only occur within a certain limited range. It is therefore doubtful whether these reactions take place at low temperatures, and that this doubt is justified is supported by the occurrence of large deposits of typical oil shales in pre-Cambrian rocks which would have been destroyed long ago had such processes been possible at temperatures of 100° C. It is beyond doubt that such rocks have been subjected to as great a temperature for far longer periods than have most of the oil-source rocks. Unless, therefore, special catalysts are invoked or the original organic material is unlike anything which has yet been investigated, it is difficult to see why the process is so selective.

The geological evidence makes it exceedingly unlikely that the oil-source rocks have been heated to temperatures more than 100° C. above normal atmospheric temperature. Some of them may have been loaded with an exceptional cover, but the majority have not. Furthermore, there is also a considerable amount of chemical evidence which indicates that many crude oils have not been subjected to temperatures above 100° C. (See Brook's contribution on 'The Origins of Petroleums'.)

A further difficulty is that all destructive distillation at whatever temperature must leave behind a residue or 'spent'. Such a material is readily identifiable, and it is unlikely that material of this type would have escaped recognition in all the oilfields which have been investigated.

For these very substantial reasons it appears very doubtful indeed whether this theory of thermal decomposition can be accepted in spite of its apparent simplicity. The arguments against it are very strong indeed, and when coupled to these arguments there arises the conviction from many aspects of geological reasoning that oil formation is not an indefinitely postponed reaction, but takes place within a reasonable period of deposition, it becomes necessary to look for some other explanation of petroleum formation.

There has been some suggestion that whereas tempera-

ture alone could not have caused the destructive distillation, it might have achieved it with the aid of catalysts or by pressure.

The first is an interesting suggestion, particularly in view of the presence of nickel and vanadium in most petroleum ashes, but it is purely a hypothesis and does not remove the other substantial objections to destructive distillation. The suggestion of pressure as the other controlling factor is, however, based on a misconception. High pressures have been used in cracking processes and in some destructive distillation in order to achieve the high temperatures required, but not as an end in themselves. It is difficult to conceive that pressure would induce a reaction which automatically involved an increase in total volume owing to the large amount of gas produced.

Another possible cause of the genesis of hydrocarbons has been suggested in the effects of α-radiation on organic matter. A difficulty incidental to this explanation is the associated formation of hydrogen which ought, on this principle, to occur with petroleum deposits. The fact that hydrogen is rarely present in petroleum gases tends to negative this possibility, though the hydrogen may have been used up in the alteration of unsaturated to saturated hydrocarbons which is considered by Barton and others to take place with time and deep burial [3, 1934]. A more serious objection to the influence of radioactivity in the formation of oil is that there is no obvious reason why it should have occurred in oil-bearing strata and not in other organic deposits.

Biochemical Formation of Petroleum.

In discussing the conditions of deposition of organic matter in marine sediments it has been postulated that all such material would be rapidly oxidized and lost unless it were deposited in an anaerobic environment. During the accumulation of this organic matter it may be assumed that it will have undergone considerable alteration. Apart altogether from the changes which arise by virtue of the consumption of the phytoplankton by marine organisms and the resultant change in the material, it must be realized that the organic constituents which fall into the sediment will be only such faecal and dead matter as can be entrained by the falling sediment. According to Trask this material will consist of complex residual ring and chain compounds which represent the final residuum after bacteriological and enzyme decay [19, 1932]. It might also contain considerable quantities of metallic soaps which would have escaped detection as such in the methods of chemical investigation adopted by Trask. The question now arises whether bacteriological decay, having reduced the nitrogen and oxygen content of the organic matter during deposition, ceases to play any further part in the transformation of the organic matter once the material has been covered by other sediments on the sea floor. Trask maintains that this is the case, and adduces as evidence his failure to find any appreciable quantity of petroleum in modern sediments. It must be realized that the materials so examined were only the uppermost layers of the marine sediments and would therefore represent only the earliest stage of bacteriological decay. This lack of success is therefore not conclusive evidence against the bacterial theory. Of more weight is the fact that all studies of such decay have tended to confirm the impression that the ultimate end product of all such decomposition tends to be methane, and until it has been proved conclusively that bacteriological decay can produce the higher molecular weight hydrocarbons, the bacterial theory can only be regarded as a tentative solution [10, 1934]. Its main basis lies in the fact that it is in agreement with the view, supported by many independent lines of approach, that the formation of petroleum, if not contemporaneous with sedimentation, takes place not long after the sediment has been laid down. The processes of biological decomposition are discussed by G. D. Hobson in 'Biochemical Aspects of the Origin of Oil' and need no further reference here.

Conclusions

Hydrocarbons may originate in many different ways in the earth's crust, but the geological conditions in which petroleum and natural gas occur in commercial quantities point overwhelmingly to the conclusion that these materials are of organic origin and they are intimately bound up with the history of sedimentation. The most favourable environment for the accumulation of oil-producing sediments is a marine one. The sediments which ultimately produce the oil are in the main clays, marls, and limestones, and the oil must have been formed from the organic matter which was enclosed in these sediments. The richness in organic matter need not have been abnormally high, for the oil and gas have been segregated and concentrated by the processes of migration. Furthermore, oil-source rocks are sufficiently widespread to indicate that they represent a normal and not an abnormal phase in marine sedimentation.

Three main essentials appear to be called for in the development of a source rock: an ample supply of sediment, a favourable environment for organic life, and anaerobic conditions of sedimentation on the sea floor. Such conditions are supplied by basinal areas on the continental shelf marginal to the land masses or to large oceanic islands.

The residual organic matter becomes enriched in carbon and hydrogen at the expense of nitrogen and oxygen as a result of the various processes of decomposition, but it is not by any means a group of hydrocarbons when it is deposited. The transformation of this material into petroleum is still a matter for discussion. One school of thought believes that it is a gradual process of thermal metamorphism taking place as a result of blanketing of the source material over long geological periods and at relatively low temperatures. The other believes that the processes occur in the body of the sediment by an extension of the processes of bacterial decay coupled with associated chemical alterations. Both of these theories involve difficulties which have not yet been overcome. The first seems to be inadmissible on various geological grounds unless it can be shown that the final residual organic material can be altered into hydrocarbons at lower temperatures and at a much faster rate than is at present conceded. The theory of biochemical decay is at present unsubstantiated by direct evidence that the higher molecular weight hydrocarbons can be produced by such action.

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ON THE ORIGIN OF PETROLEUM

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A SATISFACTORY theory of the origin of petroleum must explain its two most outstanding characteristics, abundance and great chemical complexity. An organic origin which seems to be the one most favoured at present by geologists does not appear to throw any light on its surprising degree of chemical heterogeneity.

One is confronted with the choice between admitting that the mixture of hydrocarbons which constitute petroleum had this degree of complexity from its origin or that it has become complex through subsequent chemical changes. On *a priori* grounds it has always appeared to the writer highly improbable that such a variety of molecular species should originate from a single source by any natural process in one step either chemical or biological.

The recent spectroscopic discovery that the atmospheres of our largest planets [1, 1934] which have probably never sustained life in any form consist almost exclusively of hydrocarbons, principally methane, together with Russell's [9, 1935] very plausible interpretation of this fact, may throw an entirely different light on the question, and merits consideration along with the discarded theory of the origin of petroleum through the action of water on deep-lying carbides.

It is the object of this chapter to review some of the chemical and physical factors which have a bearing on the origin and nature of petroleum.

Before examining this question further, the properties of hydrocarbons occurring in nature should be considered. The series appears to be unbroken from methane, the principal constituent of combustible natural gas up through the higher gaseous members into liquid petroleum and over into the naturally occurring solid materials such as asphalt, gilsonite, &c. Never is one hydrocarbon found alone, but always in a mixture of higher and lower members spreading out with decreasing occurrence in both directions from the centre of greatest abundance.

The possibility of such complexity statically considered, arises from the unique property of hydrocarbons and of their derivatives to form long chain compounds through the linkage of carbon atoms one to another. So long and multiple-branched are their chains that the number of theoretically possible compounds is enormous and most of them seem to be contained in petroleum, though no one of them to any large extent. The carbon to hydrogen ratio changes from compound to compound by such small steps as to be almost a continuous variable as it approaches its limiting value of 1:2 in the higher saturates. Certainly the law of definite multiple proportions would never have been arrived at, had the compounds of petroleum been the subject of study.

It is not only remarkable that such a large number of chemical compounds can be obtained from two light elements with simple valencies, but so numerous and closely spaced (chemically) are they that their separation has been and still is one of the major problems of petroleum research. Distillation is the principal method, but even this fails for final separation and can be supplemented by fractional crystallization from solvents at low temperatures. Washburn [12, 1929] and his co-workers found that fractionation is still proceeding when difference of boiling-point no longer serves as a guide, the continued fractionation being shown by changes in refractive index. The hydrocarbons contained in petroleum are not limited, however, to the saturated series, but also include naphthenes and benzenes.

On examining the general thermodynamic relationships in reactions between saturated hydrocarbons, generally one finds that they involve but small free chemical energy. For this reason, there is no driving force to cause interaction, and under ordinary conditions they are quite inactive towards each other. On the other hand, since there is no driving force in any direction, there is no large opposing force to be overcome; in other words, the heats of reaction are low. Furthermore, if suitable conditions are found to produce reaction, and since there are no large directing forces, one may expect reaction to take place in any direction and to proceed by successive steps in all directions, hence leading to great complexity of product, without having to assume such variety in the original source.

A thermodynamic treatment of possible reactions between hydrocarbons has been given by Professor H. A. Wilson [13, 1927, 1928] of the Rice Institute. Between successive members of the paraffin series in the region of temperatures of several hundred degrees and pressures from a few to several hundred atmospheres, he assumes equilibria of the type:

$$2C_nH_{2n+2} \rightleftharpoons C_{n+1}H_{2(n+1)+2}+C_{n-1}H_{2(n-1)+2}.$$

Thus there exists an equilibrium, dependent on pressure and temperature, between any member of the paraffin series and the members next above and next below in the series in point of number of carbon atoms. Since the relationship is perfectly general, it will extend in both directions: to methane and ethane at the lower, gaseous end of the series, and to solid members at the upper end. The light gases will be either trapped, and thus furnish the gas pressure associated with petroleum, or, if liberated, will allow the dynamic equilibrium to cause a chemical drift of the hydrocarbons continuously from higher towards lower members.

Wilson has pointed out that so far as his calculations are concerned, the equilibria might be purely physical ones among pre-existing members of the series, but it seems quite justifiable to make the step, as he does in his later paper, 'Theory of Cracking [14, 1930] of applying the same considerations to equilibria arrived at by chemical action. To the writer, it appears entirely logical to extend the reasoning to the processes of petroleum generation, regarding cracking and petroleum formation as entirely similar processes from the chemical standpoint, after making due allowances for such differences of physical conditions as would be necessary.

With this kind of mechanism it would be possible under influence of such temperatures and pressures as may quite reasonably exist in the earth's upper crust, to start with any member of the paraffin series and arrive at liquid

mixtures like petroleums. [This assumes that petroleums consist solely of hydrocarbons, which is not the case. Ed.]. The olefine series has been given similar thermodynamic treatment by Wilson and offers no new difficulties. Equilibria similar to those among the paraffins may be set up. Transition from paraffins to olefines could be effected by the elimination of methane. The treatment promised by Wilson for benzene and the other ring series has not yet been given. It is an interesting question whether a transition from chain to ring members could be accomplished by inorganic processes in nature, or whether the ring members originated in life processes in the primary source. While there is some evidence of the generation of benzene derivatives from paraffins by some of the vigorous agents to be next discussed, it is by no means conclusive as yet.

Besides the reactivity of hydrocarbons under the influence of heat and pressure just discussed, other more vigorous agents such as electrical discharge [7, 1928–30], alpha radiation [6, 1926], and ultra-violet light [11, 1927; 10, 1929; 4, 1930], have been found effective in causing them to interact. While all of the characteristics of these various types of agents are not as yet understood, they have one property in common which is rather surprising. In spite of the large quantum amounts of energy applied, the hydrocarbons are not generally broken down but exhibit the striking property of condensation to form liquids or solids, with only so much elimination of lower gaseous members as is necessary to avoid chemical supersaturation.

Even when spectrographic evidence indicates an intermediate dissociation of high degree, as in the work of Harkins and Gans [3, 1930] with benzene, subsequent action leads to additional products in solid and extremely inert states.

The precision of the results obtained in the action of alpha rays on gaseous hydrocarbons has permitted the development of a theory of the reaction mechanism. Whether it be direct action between ions and molecules or interaction of free radicals does not concern the present discussion vitally. The predominant result is condensation of lower to higher members on up into the region of liquids and solids [8, 1927]. The theory gained from the alpha-ray studies also predicts a great variety of products both in the paraffin and olefine series. Starting from a single member either high or low should lead to all other members above and below, distributed according to some form of probability curve with its maximum at the member having double the number of carbon atoms of that in the original molecule. The theory is confirmed among gaseous members, but owing to the scant quantity of liquid obtained under alpha radiation, fractionation of the liquid products has not been attempted. However, the same theory has been found applicable to liquids obtained by electrical discharge in single hydrocarbons [7, 1930]. The quantities of liquid thus obtained have been sufficient to permit of some fractionation. Great complexity is revealed, as expected, and the most abundant molecular species has double the number of carbon atoms of the original species; for example, octane from butane.

The application of some of these processes to the origin of petroleum may appear remote. Indeed it is so, except as the general principle may apply that when a certain type of reactions or a set of products is demonstrated to be possible through the employment of some special agent such as ultra-violet light or alpha radiation, the probability becomes greater that some conditions of temperature, pressure, or catalysis exist which render the same reactions possible with a lower quantum expense of energy.

Although electrical discharge and ultra-violet radiation are abundant in the earth's atmosphere, they are unknown in the crust and hence can play no role in the synthesis of petroleum. But, not so with alpha radiation, which, due to the universal radioactivity of the crust, is everywhere present, though in very low intensity. In their original consideration of the chemical behaviour of hydrocarbons under alpha rays, Lind and Bardwell pointed out [6, 1926] that feeble intensity of radiation might be so compensated by prolonged action through geological periods of time as to suggest a theory of the origin of petroleum from gaseous hydrocarbons under the influence of alpha radiation, provided two apparent obstacles could be overcome.

First, are there conditions in the crust under which an appreciable fraction of the alpha radiation could be absorbed by hydrocarbons? Since the 'porosity' of gas and oil sands reaches the value of 20%, it seemed probable that the fraction of alpha radiation effectively absorbed in the petroleum structure might approach that degree of efficiency.

The second obstacle appears more formidable. The action of alpha rays on all members of the paraffin and olefine series was found to result in the liberation of much hydrogen; whereas in all natural gases occurring in the United States, hydrogen is notably absent. The dilemma exists, though possibly in a milder form, whether we consider the action of alpha radiation in the earth's crust on hydrocarbons to have any connexion with the origin of or changes in petroleum or not. The absence of hydrogen in natural gases is still anomalous, since we know it must be liberated in the earth's crust by the action of alpha particles on any hydrogen-containing compounds—including water. It must then be removed from earth gases by some reaction which again fixes it, possibly assisted by contact catalysis. It might be, for example, the reduction of a metallic oxide to give water and the free metal or a lower oxide. But in the case of unsaturated hydrocarbons, the writer [5, 1931] has suggested that hydrogenation of these may be an important factor. This, of course, could not be expected to account for all the hydrogen from an original saturated hydrocarbon without the assistance of some other hydrogen-removing agent.

In the purely thermal processes of Wilson, liberation of hydrogen is not assumed. This alone would appear to make his mechanism the more probable. But neglecting this hydrogen difficulty, if we calculate the amount of petroleum in the earth's crust that would correspond to the present total of helium content of the atmosphere, on the basis that each atom originated in the crust as an alpha particle, a large total is obtained. This calculation has been made by Farr and Rogers [2, 1928, 1930] on the basis of the alpha-ray energy in producing petroleum and assuming the same yield per ion pair as found by Lind and Bardwell experimentally. The estimated total of two billion tons of potential petroleum for the Petrolia Field of Texas is so great that even after making large allowances for overestimation of energy utilization, yield, &c., the balance could still exceed the actual production. It is also to be remembered that only about 20% of the oil contained in a structure is actually recovered. Corrections in the opposite direction, such as possible loss of helium from the atmosphere leaving the present total content too low, and helium in natural gases still remaining in the earth would raise the total possible. The calculations of Farr and

Rogers also have the advantage of being independent of any time factor. It may be mentioned incidentally that some recent analyses of natural gases in New Zealand by the same authors report as much as 4 to 20% of hydrogen in 10 out of 82 samples, though the helium content in none of them exceeded 0·02%.

To sum up, it may be said that we now know processes either thermal or ionic by which progression both up and down the hydrocarbon series is effected, starting from any member in the series. This leads directly to the complexity found in natural petroleums, and also found in the electrically synthesized ones. Consequently, the starting material, whether of vegetable, animal, or mineral source, does not need to be a complex mixture, but may be a single chemical species, from which a high degree of complexity is obtained by steps which appear simple and natural when the chemical and thermodynamic properties of hydrocarbons are taken into account. The simplicity of such a mechanism may lend indirect support to the old idea of an inorganic origin from one or a few hydrocarbon gases such as might be produced by the action of water on metallic carbides in the earth's interior. On the other hand, it does not preclude animal or vegetable origin, but strongly suggests that the primary material, whether gaseous, liquid, or solid, is later subjected to thermal (or ionic) agents (or both) which produce the complexity found in nature.

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PETROLEUM SOURCE BEDS

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SOURCE beds are sediments that are or have been capable of generating petroleum. The subject of source beds is intimately associated with the problems of origin and migration of oil. As these problems are discussed fully in other articles in this treatise, only brief mention will be made of them in this report.

According to the prevailing opinion of geologists, as amply discussed by White [25, 1926; 26, 1934; 27, 1935], Snider [17, 1934], Kelly [10, 1933], and Krecji-Graf [11, 1935], the chief mother substances of petroleum are organic compounds that accumulate in near-shore marine sediments in an environment deficient in oxygen. Though most oilfields are associated with marine sediments, the possibility is not excluded that continental deposits may be source beds. In fact the gas in some fields may be derived from remains of land plants (Torrey [20, 1934]). Oil shales, which commonly are of terrestrial origin, because of their large organic content, have been postulated as sources of oil (Pratt [15, 1934] and Stadnichenko [18, 1931]). The scarcity of oilfields associated with rich oil-shale deposits of continental origin, notably the Green River shale in Wyoming, suggests that continental oil shales may not be good source beds (McCoy and Keyte [13, 1934]). Brooks [5, 1934] comes to a similar conclusion as he observes that waxes, resins, and similar substances (kerogen) such as characterize continental oil shales are so stable that once formed and preserved in the rocks they 'undergo no further chemical change whatever under the conditions of temperature and pressure existing in sedimentary rocks even of great geologic age and depth'.

Coals similarly have been suggested as a source of oil (Cunningham-Craig [6, 1923]), but the prevalence of oilfields in areas devoid of coal, such as California, argues strongly against such a hypothesis. Coal, however, may yield gas and thus be a source of gas in some gasfields. The scarcity of igneous deposits in many oil areas and the presence of barren sands beneath productive zones in numerous fields has for many years convinced most geologists that petroleum is not of inorganic origin, but Krusch [12, 1931] still believes that in some fields it is derived from magmatic emanations. Stadnikoff [19, 1930] also postulates an igneous source for the hydrogen necessary to saturate the unsaturated compounds that he regards as mother substances of petroleum.

Petroleum, presumably, is derived from special types of organic matter under particular conditions. The relative scarcity of oilfields indicates that not every type of organic matter will yield oil, and the localization of fields in certain areas, such as the Gulf Coast Province, suggests strongly that it forms under special conditions. The factors that act upon the mother substances after they have been deposited may be influential in the formation of oil. As pointed out by White [25, 1926; 26, 1934; 27, 1935], the chemical nature of the organic constituents of sediments is influenced by time, temperature, and pressure; and such factors as degree, duration, and date of folding, and also depth of burial may affect the generation of oil. Moreover, it is conceivable that under some conditions source material might generate oil, but not under other conditions. For example, in a series of alternating beds of sandstone and shale the oil might be able to migrate from the shale where it originates to the reservoir where it accumulates, but in a shale body containing a similar amount of source material but no interbedded sand the oil might not be able to reach the reservoir.

Very little is known as to the particular types of organic matter that give rise to petroleum. Oily substances may be produced by distillation of many types of organic material, but as Brooks [5, 1934] points out, these oily substances are highly unsaturated and are rich in aromatic compounds, and though mainly of a hydrocarbon nature, are distinct in composition from petroleum, which is composed of saturated substances and ordinarily contains a small quantity of aromatic compounds. However, whatever the particular substances that give rise to petroleum may be, they presumably accumulate in sediments according to the laws governing the deposition of the organic constituents in general.

The organic content of sediments depends upon the supply of organic matter in the overlying water, though it does not follow that given an equal proportion of organic matter in the water in different areas, an equal quantity will accumulate in the sediments in those areas. Currents may transport the particles of organic matter, and organisms may destroy them before or after they reach the sediments. Organic constituents, being buoyant, are easily moved by currents and are likely to be deposited with fine detrital particles that ultimately give rise to shaly deposits. The conditions under which fine sediments are laid down also favour the preservation of organic matter, because fine sediments are commonly deposited in relatively quiet water, which generally contains less oxygen than moving water and thus favours the preservation of the organic constituents (Hecht [9, 1933]).

The organic content of sediments, therefore, is definitely related to the texture. In fact, in the Channel Islands region of California, the clayey sediments on the average contain twice as much organic matter as the silty deposits, and the silty deposits contain twice as much organic matter as the fine sands. The same ratios hold throughout 5,000 ft. of Pliocene sediments in the Los Angeles basin and 30,000 ft. of strata in the Lower Cretaceous of northern California (Trask [22, 1937]). Whether or not similar ratios hold for all types of sediments has not yet been established, but the available data indicate that these ratios are of the proper order of magnitude, and that given a constant supply of organic matter in the overlying water the clays will contain more organic matter than the silts, and the silts more than the sands, but the clays in one area may contain a different amount of organic matter from the clays in another area.

In other words, shales should be the best source beds,

but sands, particularly poorly sorted sands, such as are present in the Santa Fe Springs field in California, under some conditions might be source beds (Snider [17, 1934]). Limestones deposited under conditions similar to those under which shale accumulates likewise could have a large organic content and might be source beds (Potonie [14, 1928]). The prevalence of limestones in the oilfields of West Texas supports the concept of generation of oil in limestone.

Irregularities on the sea floor, because of their effect on currents, also influence the accumulation of organic debris. Sediments deposited on submarine ridges or open slopes contain relatively little organic matter, and deposits that accumulate in basins or protected embayments have a relatively high organic content (Trask [21, 1932]). Diastrophism, because of its effect on the configuration of the sea bottom, therefore, influences the deposition of source beds. In areas of relatively pronounced earth movements, such as the Channel Islands region off the coast of southern California, or those in which the Pliocene sediments in the Los Angeles basin were laid down, the organic content of the deposits may double within 10 or 15 miles, but in quieter areas, such as those in which the Upper Cretaceous sediments in the East Texas basin and in Central Wyoming were deposited, the organic content may be remarkably constant over areas as much as 200 miles in diameter (Trask [22, 1937]). Thus, in regions of active diastrophism at the time of deposition, the organic content may vary greatly within a short distance, and inferentially the capacity of the sediments as source beds may similarly vary considerably within a few miles. Diastrophism also favours the deposition of alternating beds of sandstone and shale, and thus indirectly facilitates the accumulation of oil.

Organic matter, once it has been formed by the plankton or some other form of life, tends to decrease in quantity with time. Sooner or later it serves as food for other types of life, with the result that some of it is incorporated into the tissues of the organisms that devoured it, some of it is unassimilated, and the rest is used to create energy and is transformed to waste products, such as carbon dioxide and water. The organisms that fed upon the original matter or the unassimilated products in turn serve as food for other organisms, with the result that the original quantity is still further decreased. As long as organic matter can serve as a source of energy it will be acted upon by organisms. In the presence of oxygen it may be totally destroyed, but once it has been buried in sediment it is in an environment of little or no oxygen and ordinarily is not decomposed completely.

It is estimated that on the average at least 90% of the original organic matter is destroyed and no more than 10% is trapped in sediments (Trask [22, 1937]). This estimate is not based on sufficient data to be very reliable, but nevertheless, it is evident that under ordinary conditions a very large proportion of the original planktonic organic matter fails to accumulate in sediments. After the organic matter has been deposited, it still continues to be destroyed, presumably mainly in the upper layers of the sediments where bacteria can live. However, owing to the scarcity of available oxygen, it seems probable that bacteria, though perhaps being able to exist, do not destroy much organic matter after the sediments have been buried to some depth (White [25, 1926]). The rapid decrease in quantity of bacteria from the surface of deposits downwards is in accord with such a concept (Zobell and Feltham [28, 1934]). The presence of significant quantities of organic matter in nearly all ancient sediments likewise supports this inference.

The average quantity of organic matter in recent sediments is about 2·5% by weight (Trask [22, 1937]). This average is a median based on 1,600 samples from 150 environments of deposition from many parts of the world. The quantity, of course, varies greatly among different types of deposits. In near-shore marine sediments it ranges mainly from 1 to 7%, being large in areas characterized by plentiful plankton. In some lakes it may be as high as 40% (Potonié, 1935, see reference 8), and in some deposits in the Black Sea it is 35% (Krejci-Graf [11, 1935]). Typical oceanic sediments far from land contain 1% organic matter or less (Trask [21, 1932]).

The average organic content of several thousand samples of ancient sediments ranging in age from Cambrian to Pliocene and located in many areas in the United States west of the Mississippi River, as indicated by the analyses thus far made, is 1·5% (Trask [22, 1937]). Very few ancient sediments in existing oilfields contain less than 0·5% or more than 5% organic matter.

The analyses upon which these averages are based represent many types of sediment, and are sufficiently large in number to indicate at least the proper order of magnitude of the organic content. The difference in the average organic content of the recent and ancient sediments is 2·5 less 1·5 or 1·0%; that is, the average loss during burial is 1·0/2·5 or 40%. Individual sediments, including some or perhaps many source beds, may lose more, or less, organic matter than the average, but as a general rule it seems that the loss should be about 40%. In other words, nearly all recent marine sediments contain a significant quantity of organic matter, most of which does not seem to be destroyed in the course of time; that is, the organic constituents of sediments, in general, are composed of resistant substances.

The decrease in quantity of organic matter is accompanied by a progressive loss of oxygen and nitrogen and possibly hydrogen with respect to carbon (White [27, 1935]). According to some geologists, notably Krejci-Graf [11, 1935], sediments characterized by the greatest amount of deoxidation are the most likely to be source beds. In fact Krejci-Graf [11, 1935] argues that in order for a sediment to be a source bed, it must be deposited in a reducing environment in which practically no oxygen is present. Such conditions favour the formation of dark sediments, and many American geologists, as reported by Snider [17, 1934], regard a dark colour as a favourable indication of source beds. For want of definite evidence as to what types of sediments are source beds, one cannot say that colour is not an index of the ability of the rock to generate oil, but many light coloured sediments, some of which are associated with oil zones, such as parts of the Niobrara formation in the Rocky Mountain region, contain much organic matter, and on the contrary some dark sediments contain little organic matter. Colour, therefore, should not be regarded as an infallible index of source beds.

Some geologists believe that sediments must be extremely rich in organic matter in order to be source beds. Krejci-Graf [11, 1935] leans to this view because he holds that oil cannot migrate until an excess is produced over that which is adsorbed by clay particles which it may encounter in the process of migration, and that as clay particles have considerable powers of adsorption, a sediment must be very rich in organic matter in order to be a source bed.

However, as mentioned above, very few ancient sediments in many oilfields in the western United States now contain more than 5% organic matter. The organic content at the time of deposition was of course larger than it is now. As indicated above, the initial content probably was about 70% greater than the present content of the sediments in the oilfields. That is, these sediments in general probably contained less than 10% organic matter at time of deposition. The samples that were examined represent such great thicknesses of sediments from so many areas that it is probable that a considerable number of them are analogous to rocks that have generated petroleum. Consequently it would seem as if a very large organic content at the time of deposition is not an essential requisite of source beds, and it is almost certain that sediments that have already generated oil do not necessarily contain much organic matter. This is particularly exemplified by the Santa Fe Springs field in California, where the average organic content of some 4,000 ft. of lower Pliocene sediments which are intimately associated with the oil zones is less than 2% throughout the drainage area of the field (Trask [22*a*, 1936]).

On the other hand, though extreme richness does not seem essential, moderate richness very likely is a common characteristic of source beds. Numerous formations which contain from 2 to 5% organic matter, such as the Eagle Ford shale of Texas, the Mowry shale of Wyoming, and the Pliocene and Miocene sediments in the Los Angeles area of California, are intimately associated with oil zones. However, some sediments that contain equally as much organic matter, such as parts of the Pierre shale in Wyoming, are not contiguous with oil horizons, and some sediments that contain very little organic matter, such as some of the Carboniferous formations in Wyoming, are associated with oil zones. In other words, moderate richness, though perhaps a favourable indication of source beds, is by no means a certain guide.

Knowledge of the proportion of the organic matter that has to be converted into petroleum in order for a commercial pool to form would aid the solution of the problem of what is a source bed. In the Santa Fe Springs field of California, the proportion of organic matter that had to be transformed to oil probably is more than 2% and less than 40%, and the most plausible figure, according to Trask [22*a*, 1936], is between 5 and 10%. Other fields, especially those complicated by faults, might require different percentages of conversion.

This estimate of conversion of organic matter to oil affords a line of attack on the problem of what particular organic substances may be mother substances of petroleum. Simple proteins seem to be decomposed more or less completely before they reach the sediments (Hecht [9, 1933]), and hence probably are present in sediments in too small quantities to be main sources of petroleum. However, all sediments, both recent and ancient, contain considerable quantities of nitrogenous substances. Nitrogenous compounds ordinarily constitute 30 to 50% of the organic constituents in recent sediments, and from 15 to 30% in ancient sediments (Trask [22, 1937]). The magnitude of these quantities makes it difficult for one to maintain that oil cannot come from compounds containing nitrogen.

Cellulose has been regarded as a source of oil (Berl [2, 1934]). The quantity of cellulose in the upper layers of marine sediments at the time of deposition in general seems to be less than 1% of the organic content and even less in deeper layers of the sediments (Trask [21, 1932]). This small quantity hardly seems adequate for cellulose to be a major source of petroleum, especially since it seems as if at least 2% and probably as much as 5% of the organic matter has to be converted into oil to make a commercial pool. However, some of the organic constituents of sediments may be derived from cellulosic matter in the protoplasm of the microscopic plants in the overlying water. Brandt [4, 1898] and Waksman [23, 1934] point out that the peridineans, which constitute one of the main groups of marine organisms which form organic matter from inorganic constituents with the aid of sunlight, when dried, contain 40% cellulose. It is therefore possible that the basic organic source of petroleum might be cellulose, but if so, it almost certainly has lost its cellulosic character by the time it reaches the sediments.

Fats, also, generally are present among the organic constituents of sediments at the time of deposition in quantities of less than 1% (Trask [21, 1932]). Accordingly, it seems unlikely that fats are present in sufficient quantity to generate enough oil for a field. However, so many people, notably Engler and Höfer [7, 1909], have postulated fatty substances as the main source of petroleum that the origin of oil from fats should receive serious consideration. It is possible that such fatty substances, though originating as fats in some particular organisms in the water, may not be present as fats in sediments, but instead may be in some other form, such as metal salts of fatty acids—that is, as soaps (Wasmund [24, 1935]). As the quantity of such soaps in sediments is not yet known, it is an unsettled question as to whether they are present in a sufficient quantity to produce source beds. Even if they should be found to occur in significant amounts, it does not necessarily follow that they would be the main source of oil. The chief reason fatty substances have been regarded as sources of petroleum seems to be their low oxygen content. Most fatty acids contain two atoms of oxygen and if by some process these were removed a chain hydrocarbon would be produced. Petroleum contains a considerable quantity of chain hydrocarbons, which are almost all members of the paraffin series, but according to the data on the composition of petroleum, compiled by Brooks [5, 1934], cyclic compounds of naphthenic and benzenoid nature are commonly more plentiful in petroleum than paraffin compounds. Furthermore, as pointed out by Barton [1, 1934], petroleum as first formed may be largely naphthenic in nature and acquire its content of paraffins as it grows older. Thus, since cyclic or ring compounds form such a large part of petroleum, and since fats are chain compounds, there is at least a fair presumption that oil may in part, or even to a large degree, be formed from non-fatty constituents of sediments that contain as little oxygen as do fatty substances.

The oxygen content of the fatty acid radicals, such as palmitic acid ($C_{16}H_{32}O_2$), which might be expected to be present in sediments, is about 12%. The average oxygen content of the organic constituents of one-fourth the sediments examined by Trask [22, 1937] is calculated by him to be 16% or less. Many of these samples low in oxygen, such as those from the Eagle Ford shale, are associated with oil zones and may be source beds. It therefore seems possible that compounds which are low in oxygen, but which are not of a fatty nature, may be present in sediments in sufficient quantity to be a source of oil. The whole question is complicated by lack of knowledge of the chemical nature of the organic components of sediments, and the problem of what kind of a rock is a source bed cannot be solved until more quantitative data are obtained.

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THE CHEMICAL AND GEOCHEMICAL ASPECTS OF THE ORIGIN OF PETROLEUM

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THE earlier theories of the origin of petroleum were proposed when little was known of the chemical character of petroleum and other organic minerals: coal, lignites, kerogen, asphalts, fossil resins, and waxes. Geological knowledge relating to these organic materials was equally fragmentary when the theory of the thermal decomposition of fatty oils of marine sources, or, as it is often called, the destructive distillation theory of petroleum origin, was suggested by Warren and Storrer [47, 1865] in 1863, and later (1888) by Engler [10]. Though this theory is still widely held it has become increasingly difficult for geologists to reconcile it with the evidence of geology. Thus on geological grounds alone Illing [18, 1926] has stated that the geological evidence demands a theory of petroleum origin contemporaneous with the sediments and 'not, as the distillation theory would suppose, as a later process of metamorphism'. Beeby Thompson [39, 1925] also states: 'In seeking the origin of petroleum one must not introduce extraordinary theories for its occasional occurrence amongst unusual surroundings, but consider only such views as will account for its *extensive production and wide distribution by common processes of nature*.' The current ideas regarding source beds for petroleum have been well reviewed by Snider [31]. (See also the articles in this section by P. D. Trask and V. C. Illing.)

As the physical conditions, particularly low temperatures, have become more widely recognized, the thermal-decomposition theory has been modified. It is generally believed that the organic material originally deposited in the source sediments must have been solid or semi-solid in order to be held in the original muds and that the conversion to oil came later by the slow action of mild degrees of heat. This view was held by the late David White [50, 1935], who believed that the change of coal to higher fixed carbon ratios was evidence of a thermal effect and that the same conditions producing these changes in coals were factors in the production and alteration of petroleums. From a study of the Appalachian coal and oilfields White believed that in regions where the fixed carbon of the coal deposits exceeded 60–4% no oil would be found, and outlined so-called extinction zones where conditions of metamorphism were believed to preclude the finding of oil. The present status of the carbon-ratio theory has been reviewed recently by Thom [38]. Some support for the alteration of petroleum with age and depth, by thermal influence, is to be found in the recent studies of Barton [2, 1934] of the oils in the Gulf Coast region, who showed that in this area most of the oils become lighter and more paraffinic with age and depth. However, this relationship has been shown not to hold in Wyoming [3] and Californian fields [34]. Although petroleums may have been altered in certain instances by regional metamorphism, it is doubtful, in view of the evidence submitted in the following discussion, if heat has been the primary factor in the formation of petroleums [6, 1934].

Consideration of petroleums alone, excluding other organic minerals, would be inadequate, as much of the evidence as to petroleum origin, source materials, and physical conditions prevailing in sedimentary strata is furnished by other organic material deposited in strata of widely varying geological age.

Common Organic Minerals

In Cambrian and pre-Cambrian rocks graphite occurs occasionally in the form of small flakes. The pre-Carboniferous coals sometimes approach pure carbon in composition (ash-free basis) and sometimes contain small quantities of graphitic carbon. Graphite deposits fall into two classes: (1) bedded and disseminated deposits derived from organic matter in sediments by contact or regional metamorphism, and (2) vein deposits formed by igneous intrusions [7, 1921; 8, 1923; 25, 1912; 44, 1911].

The formation of petroleum by the thermal decomposition of the kerogen of oil shale or of coal would presumably leave a carbonized residue, possibly graphitic, assuming the gas and oil to be removed in some way to cooler absorbent strata. However disseminated, graphitic material is geologically far removed and geographically usually very remote from oil-producing strata. Mention is made of the occurrence of disseminated graphite only because the theory that petroleum has been formed by the thermal decomposition of something requires an association within reasonable distances of petroleum or natural gas, and graphite or highly carbonized residues.

The relative abundance of petroleum through the geological scale runs roughly parallel with the abundance of the other organic material and fossil remains. Although the Lima-Indiana petroleum and certain of the deeper Mid-Continent and Texas oils are derived from the Middle Ordovician, organic material does not become abundant until much later, in the thick beds of the black shale of the Devonian period. In the more recent Carboniferous period both coal and oil are still abundant, and oil is found scattered through the more recent periods down to and including the Tertiary. It is noteworthy that many oil shales, containing kerogen but little or no oil, are geologically much older than many petroleums. Probably the oldest of these shales is the New Brunswick shale which Ells [9, 1925] places at the bottom of the Cambrian series. The oil shales of Esthonia, Ontario, and Ohio are Devonian, and those of Scotland, Nova Scotia, New South Wales, and one in Brazil date from the Carboniferous period. The geological antiquity of many of the oil shales is a striking proof of the chemical stability of the organic material contained in them under conditions of temperatures and pressures prevailing in these beds during their long history. Or, in other words, the survival of such organic material, often without the formation of oil, is very satisfactory evidence against the assumption that petroleums have been formed by the thermal decomposition of organic material, at least of the kerogen type.

Perhaps the most convincing evidence of the low-temperature history of oil shale, as well as petroleum, is furnished by the recent discovery of Treibs [41, 1934–5]

that many shales, asphalts, and asphaltic petroleums contain chlorophyll porphyrins. In a discussion of the origin of oil shales George [13, 1925] states that in some of the oil shales fossil plant remains predominate and others are relatively rich in fish or animal fossil remains. Treibs found evidence of meso-porphyrin, derived from haemin, in several oil shales, which agrees with the mixed character of the fossil remains. However, in the series of oil shales, asphalts, and petroleums investigated by Treibs chlorophyll porphyrins predominated and were the only porphyrins detected in the majority of cases.

Very little is known of the chemical nature of kerogen [24, 1924]. Extraction of oil shales with solvents usually yields very little oil; for example, New Brunswick shale yields 1·36% of the shale, or about 4% of the kerogen, by extraction with various solvents [12]. Only traces of the extracted material distil below 200° C., showing the complete absence of oils of the nature of gasoline. The carbon-hydrogen ratio of kerogen in various oil shales varies from about 7·42 to 8·92. The nitrogen appears largely as ammonia, on destructive distillation, and the sulphur content is often high, forming hydrogen sulphide and a series of complex organic derivatives.

The kerogen of oil shales, in its insolubility in solvents and in the character of the products obtained on destructive distillation, closely resembles the cannel or boghead coals. Stadnikoff [32, 1930] has recently published a great deal of evidence to show that the organic material in cannel and boghead coals consists almost wholly of products of polymerization and anhydride formation of fatty acids. The oils obtained by destructive distillation contain only very little phenols, are rich in olefines, the lighter distillates contain free fatty acids and the higher-boiling fractions contain small proportions of saponifiable material, yielding fatty acids after saponification, which Stadnikoff regards as fatty acid anhydrides. The oxygen content of these oils also indicates the presence of neutral oxygen derivatives, probably ketones. The gas formed is mainly methane.

Stadnikoff gives the composition of the oil distillates of several cannel-type coals as follows:

TABLE I

Constituents of Cannel Coal Distillates

	Carbonic acids %	*Phenols* %	*Organic bases* %
1	0·04	1·70	2·02
2	0·20	1·30	1·30
3	0·14	2·35	1·68
4	0·20	3·42	1·85
5	0·50	2·00	2·00
6	0·44	1·70	0·30

Brown coals, though chemically quite different from cannel coals and oil shales, commonly contain resin and wax, the survival of which through long geological periods is striking proof of the low-temperature conditions prevailing since their deposition. Resin inclusions, resembling kauri gum, have been found in New Zealand brown coal [19, 1925]. The resin was found to consist almost completely of a carboxylic acid. Still more striking is the survival of organic esters of the higher alcohols, as in montan wax of German brown coals. This wax contains the acids [42, 1934] carboceric, $C_{27}H_{54}O_2$, and montanic, $C_{29}H_{58}O_2$, and as esters the alcohols tetracosanol, $C_{24}H_{50}O$, ceryl alcohol, $C_{26}H_{54}O$, and myricil alcohol, $C_{30}H_{62}O$. The amorphous, rather indefinite, mineral pyropissite occurring in Tertiary brown coals begins to give off gas and decomposition products on heating to 120–50° C., and on destructive distillation yields a mixture of crystalline paraffins, saturated and olefinic oils.

It has long been believed that the progressive carbonization of coals has been primarily due to heat, or to heat and pressure. Thom [38] concludes that the fixed carbon ratios of coals appear to provide a fair qualitative index of local metamorphic intensity. Regions containing anthracitic coals are apparently completely barren of commercial oil-pools. Thom also states that carbon ratios do not afford sufficiently accurate or critical evidence to warrant the drawing of 'dead-line' limits to possible oil and gas occurrence. He regards coals as 'particularly sensitive' to the influence of heat and pressure. The fact that petroleums often contain complex labile substances easily decomposed by heat may indicate that cellulose, peats, and coals are progressively carbonized under pressure and during geological time at temperatures much lower than has heretofore been assumed. Thom states: 'The assumption that oil is generated *only* by dynamo-chemical alteration of organic source materials is contradicted by what is now known of the occurrence of oil in relatively young formations.—A great proportion of the world's known oil fields of importance occur in sedimentary rocks which are entirely or almost wholly unconsolidated, and the remaining fields occur in formations which are unmetamorphosed and only partially filled with cementing materials.' In other words, the carbonization of coal, serving as a 'qualitative index of local metamorphic intensity', may indicate conditions severe enough to have *destroyed* petroleum, but cannot be accepted as evidence for the manner of petroleum formation under the very different conditions of the normal occurrences of petroleum.

It has often been assumed that the hardening of sedimentary strata, or lithification, has been mainly due to pressure and temperature. Compaction by pressure is evident and is generally progressive with the depth [26]. But in view of the very low-temperature history of petroleum which the chemical evidence indicates, it is much more probable that cementation by deposition of the cementing material from solution, together with compaction, are the primary factors.

Ozokerite is generally believed to occur as a mechanical concentration or separation of the higher melting-point, less soluble paraffins of petroleum. It is of interest in this connexion only as indicating that the conditions of temperature and pressure of the deposits in which it is found have not been sufficient to change it to mixtures resembling petroleum. The occurrence of ozokerite is an indication that petroleums are not so-called equilibrium mixtures of hydrocarbons produced by heat and that such hydrocarbons, once formed, may be separated, filtered, and absorbed and concentrated but not chemically changed by natural conditions.

Natural Gas

Methane, though now known to be a major constituent of the atmosphere of some of the planets [29, 1935], and known to be formed from certain metallic carbides by the action of water, is also formed by the common anaerobic fermentation of cellulose. The composition of natural gas accompanying petroleum has a definite bearing on the genesis of petroleum. Natural gas contains no trace of hydrogen, carbon monoxide, or ethylene; gas formed by

the pyrolysis of fatty acids or natural fats, as in Engler's experiments, contains all three of these substances. Although ethylene and carbon monoxide can be hydrogenated under suitable conditions and in the presence of specially prepared catalysts, it is not reasonable to assume that these three substances would always be produced by pyrolysis in exactly the proportions required for their subsequent complete elimination by hydrogenation. The absence of hydrogen in natural gas accompanying petroleum is also very strong evidence against the theory, suggested by S. C. Lind [21, 1931], that petroleum has been formed by the action of alpha radiation from radio-active minerals on methane, since hydrogen is formed in large proportions from methane in the process.

The occurrence of helium in small proportions in natural gas in certain localities, in the light of the evidence of organic origin, is to be regarded as an adventitious constituent probably derived from primitive granites beneath the sedimentaries, as in the case of the old buried granite ridges in the Mid-Continent area of the United States, or from secondary radio-active minerals in certain sedimentaries, as in the Shinarump conglomerate of Colorado.

Natural Occurrences of Hydrocarbons

Recalling Beeby Thompson's [39, 1925] statement regarding 'common processes of nature', it should be noted that saturated paraffins and olefinic hydrocarbons of widely varying types are found in nature, produced by biochemical processes at ordinary temperatures. At least 15 normal paraffin waxes occur in the essential oils of about 25 plant species, as in the oil of roses, the buds of the sweet birch, tobacco, &c. The source of pure normal heptane, used as a standard reference fuel in the determination of knock rating, is two pines in the western United States, *P. sabiniana* and *P. jeffreyi*, and also a prune-like fruit in the Philippine Islands. The chemical mechanism by which such paraffins are formed in growing plants is quite unknown, and while it is obvious that petroleum has not been formed by accumulations of hydrocarbons from such sources, their natural occurrence is important as showing that 'the processes of nature' can produce them, at normal temperatures. The natural paraffins are not associated with fatty acids of the same or C_{n+1} carbon atoms, and many contain more carbon atoms than any known fatty acid.

The terpenes, $C_{10}H_{16}$, the sesquiterpenes, $C_{15}H_{24}$, and the rubber hydrocarbons, rather widely distributed in nature, appear to be related to the C_5 group of the pentoses and the pentosans, from which they may be derived by biochemical processes of dehydration and reduction (or biochemical hydrogenation).

It is not at all necessary to assume that a high energy-input is necessary to accomplish such reductions. Such changes are observed to occur with very little net energy-change by the conversion of part of the original material to an oxidized state and part to a reduction product, as in the conversion of sugar or glucose to carbon dioxide and ethyl alcohol, and the fermentation of cellulose to methane, carbon dioxide, and small proportions of other products. One of the significant corollaries of the discovery of chlorophyll porphyrins in petroleums, asphalts, and oil shales is that the original organic material associated with these porphyrins passed rather quickly into an anaerobic environment, since chlorophyll is rapidly destroyed in aerobic fermentations. It is possible that anaerobic fermentations will be discovered which will produce ethane, propane, and other hydrocarbons.

The Composition of Petroleums

Our knowledge of the composition of petroleums is now much more extensive than when the theory of thermal decomposition was first suggested. The facts as to composition which have a bearing on the question of petroleum origin may be stated briefly.

The relative proportions of paraffins, naphthenes, and benzenoid hydrocarbons, wax, and asphalt in petroleums are summarized by Stadnikoff [32, 1930] as follows:

TABLE II

Average Composition of Typical Petroleums

Type of crude	Wax %	Asphalt %	Composition of 250–300° C. fraction: Paraffins	Naphthenes	Benzenes	Specific gravity of residue over 300° C.
Light paraffinic	1·5–10	0–6	46–61	22–32	12–25	0·897–0·929
Paraffin-naphthene	1–6	0–6	42–5	38–9	16–20	0·897–0·908
Naphthenic	trace	0–6	15–26	61–76	8–13	0·895–0·912
Benzenoid	0–0·5	0–20	0–8	57–78	20–35	0·950–0·970

The light, low-boiling fractions contain the largest proportion of paraffins. No petroleum has ever been found which contains unsaturated hydrocarbons of the olefine type, at least in the lighter distillates which can be separated by distillation without decomposition. The hydrocarbons of the C_nH_{2n} series are naphthenes and those of the higher carbon ratios C_nH_{2n-2} to C_nH_{2n-8}, &c., occurring in the lubricating-oil distillates, are evidently polycyclic hydrocarbons. According to Mabery [22, 1923] the distillable lubricating fractions of Cabin Creek petroleum are mainly of the series C_nH_{2n-4}; the distillable lubricating-oil fractions of Baku oil are mainly of the series C_nH_{2n-10}, and the corresponding fractions of Sour Lake, Texas, oil are of a series C_nH_{2n-12}. Mabery also showed that many of the hydrocarbon fractions separated from undistilled residuum by the action of solvents were sensitive to heat and could not be distilled under a good laboratory vacuum without decomposition.

Nitrogen Bases

J. R. Bailey [1, 1930] and his co-workers have shown that certain Californian petroleums, having a relatively high nitrogen-content, yield no bases on acid extraction, but that the distillates contain bases which are readily extracted by dilute acid. Their observations show that the crude petroleum contains complex nitrogen derivatives which are sensitive to heat and are rapidly decomposed at temperatures above 200° C., in the kerosine boiling range, to give nitrogen bases as decomposition products. A recent private communication from Treibs reports that the Californian petroleums which yield distillates containing nitrogen bases are also relatively rich in chlorophyll porphyrins and that a study of these oils is in progress.

The discovery of chlorophyll porphyrins in asphalt and asphaltic petroleums by Treibs [41, 1934–5] is probably the most significant discovery ever made with respect to the origin of petroleum. Its significance is in showing a complete history of temperatures so low as definitely to preclude the formation of petroleum by thermal decomposition of fatty oils or any other known likely raw material.

From the presence of aetio-porphyrins which are formed

by loss of CO_2 from the corresponding acid derivatives, Treibs concluded that the organic material may have been heated to a temperature as high as 200° C., but evidently overlooked the fact that decarboxylation of chlorophyll porphyrins takes place in a few hours in the digestive tract of animals.

Asphalts

All asphalts examined and all asphaltic petroleums contain chlorophyll porphyrins. Treibs considers that the clear asphalt-free oils had lost their porphyrin content by adsorption during filtration through absorbent material. These results also show that chlorophyll-bearing plants (algae) existed as early as Devonian and probably as early as Silurian time. Owing to the rapidity with which these chlorophyll derivatives are decomposed by oxidation, Treibs considers that their presence in oil shales, asphalts, and asphaltic oils indicates that in the original deposition of the organic material anaerobic conditions must have been brought about quickly, as by covering with sediment. The same consideration definitely excludes the assumption that asphalts have been formed by the oxidation, by air or evaporation, of petroleum. As Treibs states: 'In oils of medium viscosity, with considerable asphalt content, one has a more original oil, while the thinner, lighter colored oils represent natural raffinates.' He further suggests that one can expect that certain classes of substances will be found very little changed in petroleums and bitumens.

In the case of a Triassic oil shale from near Meride in Croatia, Treibs found 0·4% of porphyrins, corresponding to more than half as much as the chlorophyll content of dried green leaves. In contrast with the porphyrin content of oil shales and asphalts and asphaltic petroleums, lignites and cannel coals showed only traces of porphyrins. This indicates that the source material of coal was very different from that of petroleum or that the prevailing biochemical conditions were very different.

The discovery of chlorophyll porphyrins in oil shales, asphalts, and petroleums suggests that green algae may have contributed largely as source material for petroleums [15, 1932]. Few chemical studies of algae have been made. Some algae contain much fatty oil, but Stadnikoff [32, 1930] has pointed out two instances where abundant growths of algae result in semi-solid materials consisting largely of products derived from the fatty oil content. In a shallow brackish lake in southern Russia an abundant growth of green algae, *Bobriococcus braunii*, forms masses of rapidly fermenting materials, evolving hydrogen sulphide, and when air dried yields a material 'balchaschite' which is semi-solid and which consists largely of polymerization products of unsaturated fatty acids. Stadnikoff and others, however, consider this material as probably related to cannel coal or boghead coals. In a lagoon in southern Australia Thiessen [37, 1925] observed the formation of masses of semi-solid fatty material from the algae *Elaeophyton coorongiana*. A sample of the material, called coorongite, gave 5·7% of oil consisting in part of non-saponifiable oil. These results, together with the findings of Treibs, suggest that oil-bearing algae may have been an important source material of petroleum. Certainly we can no longer confine our speculations to fatty oils of fish, foraminifera, or diatoms.

The fatty material from algae, such as coorongite, forming first a waxy or semi-solid substance fulfils the condition advanced by many geologists (that the original source material of petroleum must be solid or semi-solid in order to be deposited and preserved in the forming sediments. Trask and Hammer [40, 1932], in a thorough study of contemporary sediments, found practically no organic matter in the form of extractable oil.

Naphthenic Acids

Petroleum naphthenic acids are usually separated from the distillates or from the alkali soaps formed in the still residues when the oil is distilled in the presence of caustic alkali. Pyhälä [28, 1933] found in the case of two Russian petroleums that the distillates contained 11 to 12 times as much naphthenic acids as the undistilled crude oils, indicating that, like the nitrogen bases, the naphthenic acids are mainly decomposition products of more complex materials which are readily decomposed on heating. Von Braun [45] has shown that petroleum naphthenic acids are of three general types, aliphatic $C_nH_{2n}O_2$, monocyclic $C_nH_{2n-2}O_2$, or bicyclic $C_nH_{2n-4}O_2$. Some of them are optically active. Petroleum from north Germany, Roumania, California, and Texas all contain the same monocyclic and bicyclic types of acids. The monocyclic acids are derivatives of cyclopentane $C_5H_9\cdot(CH_2)_xCO_2H$. The only similar acids found in nature are the chaulmoogric and hydnocarpic acids of chaulmoogra oil, which acids contain the cyclopentene group. Acids of this type are so rare in nature that the structure of the petroleum naphthenic acids appears to be evidence of their formation by decomposition of polymers of unsaturated fatty acids originally present in the petroleum source material.

Sulphur Derivatives

Practically all the sulphur derivatives so far investigated have been those found in the distillates, and particularly cracked distillates produced by cracking processes. Thiophenes have been found in the latter, and in shale oils, but it is doubtful if they occur in undecomposed petroleum. Kewley [20, 1934] has stated that certain crudes yield sweet distillates, free from mercaptans, if distilled under vacuum below 140° C., but at this temperature decomposition of complex labile sulphur compounds takes place with the formation of mercaptans. It has been pointed out by Gruse [14, 1928] that the sulphur and nitrogen compounds in crude petroleums, prior to distillation, are for the most part unknown.

Optical Activity

The fact that the higher-boiling fractions of petroleum show optical activity has long been regarded as disposing of the theory of the origin of petroleum from carbides. It is equally of importance as evidence against the more recent suggestion of Lind [21, 1931] that petroleum may have been formed from methane by the action of alpha radiation. In the light of other evidence as to low-temperature history it should be recalled that Walden [46, 1906] regarded this fact alone as proving a relatively low-temperature history. The optical activity of oils derived from cholesterol has been noted by Zelinsky and Steinkopf [33, 1927].

The above facts show clearly that we now know petroleum to contain many complex substances which are unstable even to moderate temperatures. Many of them are decomposed by heat much more readily than are the fatty acids or the hydrocarbons.

Complexity of the Hydrocarbon Mixture

Probably one of the reasons for the persistence of the thermal decomposition theory is the large number of hydrocarbons present in most petroleums. Petroleums contain the normally gaseous hydrocarbons, methane and ethane, dissolved under pressure, and also contain the normal paraffins and some of the branched-chain paraffins, from propane up to those of more than 25 carbon atoms. They also contain a large number of cyclic, polycyclic, and benzenoid hydrocarbons. The range of composition with respect to types of the major constituents is shown in Table II.

Wilson [51, 1927–8, 1930] has pointed out that in both the paraffin and olefine series the change from one or a few hydrocarbons to a great many of the same series involves no great amount of net energy change or reaction heat. However, one of the puzzling facts is the universal presence of small proportions of benzenoid hydrocarbons. Francis [11, 1928] has also treated this subject from the thermodynamic standpoint, and states that the formation of aromatic hydrocarbons from paraffins requires temperatures within the range of 550–900° C. This evidently assumes the splitting off of hydrogen. According to Francis, the reactions possible below 550° C. are quite *different in kind.* It is therefore wrong to assume that the formation of benzenes which is characteristic of the results obtained experimentally above 550° C. may also proceed at the much lower temperature associated with petroleum deposits at much slower rates during geological time.

The extremes of petroleum composition, as shown in Table II, should also be noted. If what may be termed the hydrocarbon dispersion and isomerization has been due to heat, even at relatively low temperatures over long periods of time, then petroleums would be much more alike in composition, would, in fact, be *equilibrium mixtures.* However, the differences in the chemical character of petroleums is much greater than can be reasonably explained by different intensity or duration of thermal action.

Barton [2, 1934] has observed certain general consistencies between the A.P.I. gravity and composition as related to depth and age of petroleum in the Gulf Coast area which if borne out in other fields, or if the exceptions could be satisfactorily explained, would at least show that petroleums are progressively altered with depth (temperature and pressure) and age. In this connexion it is of interest to note, as pointed out by Barton, that the naphthenes and *benzene* hydrocarbons occur in the largest proportions in the youngest and shallowest Gulf Coast oils. The older and deeper oils in this area are lighter and more paraffinic. Washburne [48, 1919] has argued, from general theoretical principles, that if altered by heat and pressure the older oils should be the heavier and contain the largest proportions of naphthenes and benzenes. Pratt [27] states: 'Whatever may be the exact sequence and nature of events in petroleum genesis, a theory of uniform and progressive cracking does not explain the observed facts.' These considerations led Pratt to suggest that petroleums were progressively hydrogenated, the hydrogen being derived from methane. The experimental conditions for decomposing methane and hydrogenating heavy oils are more extreme than for cracking alone. It should be noted, however, that Healdton, Texas, oil and many of the Wyoming and Californian oils do not follow the general relations shown by the oils of the Gulf Coast area.

The temperatures observed in the producing strata are significant. Some of our most prolific fields yield their oil from geologically recent sands whose bottom-hole temperatures do not exceed 100° F. and whose strata are only slightly arched or otherwise disturbed. It has often been assumed that even slow uplifts and bending of the strata could produce temperatures sufficient for the decomposition of organic material. Mere compaction is no doubt often mistaken for thermal metamorphism. Heald [17, 1930] states, 'Not enough measurements are available to permit any conclusion as to the possible influence of a great, gentle uplift like the Bend arch on earth temperatures', and that in wells thus far measured the depth of the granite basement has had no relation to the temperature. At Oklahoma City a temperature of 100° F. is encountered at 4,100 ft. In south-west Texas a rise of 1° F. for each 50 to 60 ft. is noted, while in the Permian Basin of West Texas and the Panhandle area the temperature rise is 1° F. for about 100 ft. of increasing depth. It may reasonably be assumed that the present bottom-hole temperatures are much higher than the temperatures of the original sediments when laid down, and that the present temperatures may be at or near the maximum for the entire period. The temperatures observed at the bottom of wells about 8,000 ft. in depth vary from about 150° F. to 170° F. [43, 1928]. McCoy and Keyte [23] state, 'Most of the known oilfields surely were formed at temperatures lower than 140° F.', which is far below the temperature required to decompose or isomerize oils such as paraffins, naphthenes, and benzenoid hydrocarbons at any measurable rate. Seyer [30, 1933] has employed the velocity constants for cracking, determined by others, and calculated that at 212° F. the higher paraffins have a stability greater than the element potassium, and the 'one-half life period' is about $3{\cdot}68 \times 10^{14}$ years and that 'any buried waxy material must have been at a temperature of at least 302° F. to allow for its transportation into petroleum within the limits of geological time'. In fact, the one-half life period for the decomposition of wax at 302° F. (150° C.) is $1{\cdot}15 \times 10^{10}$ years. Study of the lead-uranium ratio of the mineral cyrtolite, found in a pegmatite intrusion at Bedford, New York, which intrusion geologists place as dating from the Early Ordovician, shows the age of the Early Ordovician to be about $3{\cdot}8 \times 10^{8}$ years. Then, according to the reaction velocities calculated from measured cracking rates, about 20 times the *whole* of geological time since the Ordovician and a temperature of 300° F. for the whole of this time would be necessary to decompose half of a quantity of buried wax to oil or other products.

Using the temperature gradient observed in the Permian Basin of West Texas, no petroleum should be formed by heat decomposition in geological time short of a depth of about 28,000 ft.

In making his calculations, Seyer was seeking evidence for the formation of petroleum by heat decomposition. He was led like Washburne to reason that dense saturated molecules with a low hydrogen-carbon ratio, such as the polycyclic naphthenes, should be produced to a greater and greater extent with increasing time, temperature, and pressure. Exactly the opposite is strikingly shown by many light, highly paraffinic but geologically old oils and the wax-free, heavy naphthenic oils of many of the Gulf Coast and Californian pools of much more recent origin as already noted.

No entirely consistent relationship has been discovered

between the composition of petroleums and their age or depth of occurrence. The question is evidently complicated by alterations in composition due to selective adsorption of asphaltic and other material of high molecular weights during migration of oil through the rocks, to chemical reaction with sulphur and perhaps other causes. It appears to be more probable, and also more consonant with the evidence of low-temperature history, that the wide variations in chemical character of different petroleums have their origin chiefly in the character of the original material deposited in the submarine sediments, or possibly in differences in the biochemical influences in the early stages of their history [6, 1934].

Pressure may conceivably have had a marked effect in the formation of petroleum, although the hydrostatic pressures even in our deeper wells seldom exceeds 150 atm. Pressure, in general, favours polymerization of olefinic materials, but the ease with which many unsaturated substances polymerize spontaneously indicates that the effect of the rather moderate pressures, particularly at shallow depths, may have been important. The formation of coorongite and balchaschite from the fatty oils in the algae, noted above, indicate that polymerization of unsaturated fatty oils to solid or semi-solid material is one of the first changes to take place, as suggested by Stadnikoff [32, 1930]. The highly insoluble character of the kerogen of oil shales and most of the organic material in cannel coals indicates that it is highly polymerized. Evidence that such material contains cyclic or naphthenic groups is furnished by Stadnikoff, who found bicyclic hydrocarbons of the series C_nH_{2n-2} as major constituents of the oil produced on hydrogenating a Siberian boghead coal by the method of Bergius. A lower degree of polymerization, or less unsaturated character of the original material, may account for the lubricating oil fractions of petroleum. Engler suggested that polymerization of olefines possibly accounted for the presence of naphthenic hydrocarbons in petroleums. The polymerization of the more reactive olefines by fuller's earth is well known, and it has recently been shown that this property is by no means confined to fuller's earth, but is a property of a wide variety of sedimentary rocks, particularly the clays and shales and to a lesser degree the sandstones [5, 1931].

In view of the evidence given in the preceding pages, the conclusion may be warranted that organic materials as stable as the paraffins, waxes such as the Montan waxes and the kerogen of oil shale, once formed and sealed in the sedimentary rocks *normally undergo no further changes due to the influence of heat*. If this view is correct, then the problem of how a few paraffins may be chemically 'dispersed' and rearranged to a great number of hydrocarbons does not exist. Rather, the hydrocarbons found in petroleum must mainly have been formed as such in the gradual biochemical anaerobic degradation of the organic materials buried in the sediments.

Possible Source Materials for the Biochemical Production of Petroleum

Students of petroleum geology have differed widely as to the source material and source beds of petroleum. Probably very few believe that petroleums have been derived entirely from one type of material. However, the present discussion has to do with the chemical types of raw materials; and indirectly with physical or geological conditions which are indicated by the chemical evidence. The work of Treibs showing the derivation or association of petroleum source material with chlorophyll-bearing algae or plant life implies a shallow water plankton. There is much geological evidence for such conditions of deposition which cannot be reviewed here.

The principal types of organic substances which have to be considered as the main source material for petroleum are as follows:

(1) **Cellulose.** Cellulose readily yields methane under anaerobic conditions. The fact that methane is formed in peat and remains in certain coals, entirely unaccompanied by oil, is evidence that cellulose alone does not produce the higher paraffins, or oil, by any anaerobic fermentation, with which we are familiar. The fact that the reduction of carbon monoxide, by hydrogen in the presence of cobalt catalyst, as in the Fischer process, or that cellulose can be converted by hydrogenation under relatively high temperatures and pressures with caustic soda as carried out by Berl [4, 1934], to a series of paraffins, may be significant although no result of this nature has been observed as a result of biochemical reduction. The conditions of Berl's and Fischer's processes are far removed from natural conditions.

(2) **Starches and Sugars.** Water-soluble sugars would, of course, quickly be lost. However, Taylor [36, 1928] has shown that sugars and starches undergo anaerobic fermentation in the slightly alkaline conditions under a layer of sodium-clay yielding products which are entirely gaseous, the gas consisting principally of methane.

(3) **Proteins.** These are rapidly and almost completely destroyed by putrefaction. Small proportions of protein degradation products may be preserved under anaerobic conditions and may account for the nitrogenous material in petroleum which yields nitrogen bases. Sulphur, as free sulphur, hydrogen sulphide, and complex sulphur derivatives are so abundant in many crude petroleums that the reduction of sulphates would appear to be more plausible as an original source. Clays such as fuller's earth have been shown experimentally to catalyse the formation of mercaptans by the addition of hydrogen sulphide to olefines. Hydrogen sulphide has been observed in abundance in the fermentation of the masses of algae incident to the formation of balchaschite. Simple amines of the type of ptomaines have not been found in petroleums.

(4) **Lignins.** Lignins are very resistant to microorganisms, and are converted to humic acids. However, they may be broken down under conditions not yet observed or studied. Taylor [36, 1928] states that by anaerobic fermentation under the alkaline conditions resulting from base exchange under sodium-clay lignin was attacked. Lignin is the only natural organic material occurring in abundance which may have furnished the benzene derivatives found in petroleums without assuming high-temperature conditions.

(5) **Oleo-resins.** These generally lose their volatile oils, as in amber, the fossil copals, resinous inclusions in coal, but the resins are preserved through long periods of geological time.

(6) **Waxes.** The natural waxes, consisting mainly of esters of the higher, solid alcohols, and complex organic acids, are also exceedingly resistant under natural conditions. They do not appear to be attacked by microorganisms. The waxes in peat show no appreciable change in composition with increasing age.

(7) **Fatty Oils.** It has long been known that fatty oils are hydrolysed in a few years, losing their glycerine. Wells and Erickson [49, 1933] found that a solid material,

obtained from the wreck of a small ship which had carried a cargo of herring, consisted chiefly of the calcium and magnesium salts of the fatty acids of herring oil, and suggested that in the presence of sea-water the formation of such insoluble fatty salts may be one of the early processes involved in the formation of petroleum.

That the putrefactive decomposition of the organic matter deposited in the sediments is an initial step in the formation of petroleum has long been generally recognized. Engler [10, 1888–9, 1897, 1912] suggested that fatty acids probably lose CO_2 at an early stage. The prevailing opinion, however, seems to be that bacterial action soon ceases altogether. Probably few subjects have been the object of so much speculation and so few attempts to obtain experimental evidence as the question of the role of bacteria in the formation of petroleum. There is no published evidence of the actual formation of liquid hydrocarbons by bacteria. McCoy and Keyte [23] note that following initial putrefaction the decomposition by anaerobic forms must proceed at a very slow rate, a condition necessary for the retention and later accumulation of the material. That many species of bacteria found in soil waters are able to utilize petroleum or the more complex hydrocarbons under aerobic conditions appears to be well substantiated. Tausz and Donath [35, 1930] found that in general the ease with which a hydrocarbon is attacked increases with the length of the chain. However, very few anaerobic studies have been carried out. The work of Taylor on the slow anaerobic degradation of fatty oils and fatty acids under sodium-clay appears to be the only experimental study of such changes thus far published. Triacetin formed methane and tributyrin formed 'gaseous paraffins'. Stearic and palmitic acids were slowly attacked, but the products formed were not determined. At present the depth in the sediments at which bacterial action ceases is much in dispute. Unfortunately the poorer the experimental technique the deeper bacteria are likely to be reported.

Petroleum in Transition Stages

Entirely aside from chemical considerations, geologists have stated that the organic source material from which petroleum has been formed must originally have been deposited in the sediments as solid or semi-solid material, the oil and gas now found being sealed from escape by overlying impervious clays or shales. This is consistent with the findings of Trask, whose samples were collected at or near the surface of the sediments.

Engler recognized the differences between his unsaturated distillates, made by the pyrolysis of fats, and petroleum, and suggested the term protopetroleum for the undiscovered transition stage of petroleum, assuming such a material to be derived from fats by thermal decomposition. No material resembling Engler's distillates has been found in nature. The findings of Trask, the solid mixtures of coorongite and balchaschite formed from algae, the discoveries of Treibs, and the observations of Taylor all harmonize with the primary physical requirement postulated by geologists. Accordingly it might be expected that protopetroleums in transition stages will be found in geologically recent strata, in the form of solid or semi-solid material. Such material might be expected to be a mixture of hydrocarbon oils together with polymerized fatty or naphthenic acids. The writer suggested several years ago (Rochester, New York, 1931) that asphalts might repay investigation from this point of view. Certainly asphalts are not oxidation products of petroleum, but rather their oxygen content has survived from the original source material. The findings of Treibs are certainly strong evidence for this point of view. Asphalts would appear to be either petroleum in transition or 'near-petroleums' formed coincident with petroleum. It has often been suggested that the source material of petroleum has been laid down in estuarine sediments. The anaerobic conditions which Treibs's findings require and which Taylor's work suggests demand rather rapid or frequently intermittent sedimentation. The study of the organic material, probably still well disseminated, in Tertiary and Recent deposits which fulfil these conditions may fill in some of the gaps in the chemical history of petroleum.

Conclusions

1. The geological antiquity of organic minerals other than petroleum, particularly the kerogen of oil shale, indicates a low-temperature history.
2. The temperatures of our deeper wells, about 170° F., are not sufficient to decompose or 'crack' paraffin hydrocarbons within geological time, according to the calculations of Seyer, without assuming some now unknown catalytic agencies.
3. Petroleums contain several types of constituents which are more easily decomposed by heat than the hydrocarbons or fatty acids. These labile constituents are complex substances which yield nitrogen bases, naphthenic acids, and sulphur derivatives. The presence of optically active constituents is also evidence of low-temperature history.
4. The presence of chlorophyll porphyrins is evidence of (*a*) low-temperature origin and history; (*b*) derivation of petroleums or association of the original organic source material with chlorophyll-bearing plant life, probably marine algae; (*c*) anaerobic conditions during or intermittently during the deposition of the original source material.
5. The chemical evidence agrees with the maximum temperature of petroleum formation, 140° F., suggested by McCoy and Keyte. The chemical evidence is consistent with the general conditions of deposition and oil formation postulated by geologists.
6. Petroleums are not equilibrium mixtures.
7. The wide differences in the compositions of petroleums probably relate to the differences in original source materials or to biochemical history.
8. Asphalt is a primary product, not a derivative or oxidation product of oil.
9. Fatty oils are still to be regarded as the principal source material of petroleums.
10. The indicated low-temperature history of petroleum favours the view that the hardening or so-called lithification of sedimentary rocks is due entirely to compaction and the deposition of cementing material from solution.

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BIOCHEMICAL ASPECTS OF THE ORIGIN OF OIL

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I

CERTAIN features of crude petroleum point to its having had a low-temperature history, and to the unlikelihood of its ever having attained a temperature such that purely thermal cracking could have transformed organic matter to petroleum in the period of time available. Seyer's [14, 1933] computations from the known data regarding cracking velocity constants and heats of activation, put the half-period for Rangoon wax, which he considers as a possible proto-petroleum, at $3{\cdot}68 \times 10^{14}$ years at 100° C., and $3{\cdot}2 \times 10^{6}$ years at 200° C. Yet Barton [1, 1934] states that the Gulf Coast crudes now produced cannot have attained temperatures even as high as 100° C. Some of the deeper ones may have reached 70° C. or a little more, but many cannot have been above 50° C. The mere presence of optical activity is said to be sufficient evidence of a low-temperature history. Many of the hydrocarbons present in petroleum are sensitive to heat and not distillable without decomposition, even under good vacuum. Certain of the nitrogen bases, sulphur and oxygen compounds are similarly decomposed. Treibs claims to have found chlorophyll compounds, which cannot have been at temperatures as high as 200° C., in many crude oils. Furthermore, it seems probable that primary migration of the oil from the source to the reservoir rock must occur before depth of burial, with consequent compaction, can have raised the temperature sufficiently to bring about thermal decomposition of the source material. Therefore, the agent capable of transforming organic matter to crude petroleum must be active at temperatures well below 100° C. Biochemical processes seem to fulfil this condition.

Many relatively stable compounds are easy prey to fermentation. Simultaneous oxidation and reduction of different parts or components of the source material permit the transformations to be carried out with little net energy change. Micro-organisms are known to effect reactions of this type. Clark [4, 1926] records that fossil bacteria have been found in oil rocks and that petroleum has been found in recent bacterial deposits. Living bacteria have been obtained from the oil-water mixtures produced from rocks of various ages, but absolute assurance of non-contamination by more recent percolating-surface waters seems to be lacking. In Lake Mendota, wet mud from 2 ft. below the surface of the deposits contained 60,000 bacteria per g.; 6 ft. below, 2,000 per g., and 8 ft. below, 5,000 per g. With increase in depth there was an apparent disappearance of carbonaceous matter from the deposits. Kuhr (Bastin [2, 1926]), found sulphur bacteria in sand and intercalated dark clay layers at depths of 10 to 37 m., and sulphate-reducing bacteria have been found in the deposits of the Black Sea at depths of 2,118 m. Zobell and Anderson [20, 1936] have observed as many as 420,000,000 bacteria per g. in marine sediments, and rarely less than 10,000 per g. The numbers fell off after the first few centimetres in the sediment. About 25% of the forms isolated were proteolytic. Most samples had 5 to 15% capable of reducing nitrates and nitrites, lipolytic species, and generally sulphate reducers, cellulose decomposers, and methane organisms.

As a rule, micro-organisms and the enzymes by which they work are seriously damaged or destroyed by temperatures of 60 to 100° C., depending on the conditions, but low temperatures, say, 0 to 10° C., are not harmful. At times there are more bacteria in deep water with temperatures of 3 to 7° C. than in shallower water with higher bottom temperatures. Marine bacteria multiply and are physiologically active at temperatures below zero, and while low temperatures retard their multiplication, they favour their prolonged survival. The temperature coefficients of biochemical reactions are fairly high. In addition, bacteria and enzymes have a temperature of optimum activity which is not independent of the time factor considered. Since bacterial decompositions on complex media with a variety of organisms present are usually a chain of reactions, at temperatures removed from that which gives a maximum yield of a given end-product in a set time, other intermediate compounds may become apparent and accumulate, owing to the succeeding reactions not being able to utilize them as quickly as they are formed. In January 1927, Trask [17, 1932] found the surface temperature of the deposits in Pamlico Sound to be 3·4 to 5·5° C., and 10 to 14·5° C. at a depth of about 130 cm. in the sediment. In May 1927 the temperature of the surface of the sediments in the Potomac estuary was 16° C.; at a depth of 210 cm. it was 11·5° C., and at 430 cm. 13·5° C. Laboratory incubations are often carried out at 30° C., which is considerably higher than the temperatures under which natural decompositions may begin.

In trying to obtain hydrocarbons by biological processes in the laboratory, it must be remembered that bacterial forms and activities vary under different external and chemical conditions. Fermentation may not take place or may follow a rather different course when using relatively pure materials. Some of the forms produced may be abnormal and incapable of reproduction, whilst others may persist only so long as the special conditions obtain, and may develop properties which are latent, absent, or masked in the original strain. These variations can become more or less stabilized and continue under a variety of conditions. Waksman [18, 1927] found that some cellulose-decomposing organisms, if kept under laboratory conditions for any length of time, especially on nutrient agar media, undergo marked physiological changes which may include loss of cellulose-decomposing power. Similarly, Ginsburg-Karagitscheva [5, 1933] observed that the presence of oxygen caused bacteria from Grozni wells to change from rods to cocci-shape and simultaneously become incapable of causing fermentation. It is not impossible that under moderately high pressures micro-organisms may form rather different compounds from a given substrate from those produced under atmospheric pressure, for pressure aids the polymerization of unsaturated substances in particular.

II

Organic matter, whether animal or vegetable, is a protein-carbohydrate-fat complex, often containing unsaturated compounds, whereas petroleum is dominantly hydro-

carbon, saturated and with relatively small amounts of sulphur, nitrogen, and oxygen in combination. What, then, are the transformations which have been shown to be produced by micro-organisms?

Proteins and Amino Acids.

It has been generally accepted that proteins are decomposed rapidly and almost completely, leaving sulphur in the muds. Thus Ruttan and Marshall [13, 1917] found only 0·665% of protein in adipocere from a pig which had been buried 45 years. Proteins are first hydrolysed by bacteria and fungi to the constituent amino acids. Further action leads to a variety of changes, dependent on the materials and the conditions. Under anaerobic conditions, which are most likely to occur in oil-source beds, the amino acids may undergo deamination and reduction to form saturated acids:

$$R\text{—}CH(NH_2)COOH + H_2 = R\text{—}CH_2COOH + NH_3.$$

But deamination can take place without reduction, to form an unsaturated acid. A third change is decarboxylation with the production of an amine:

$$R\text{—}CH(NH_2)COOH = R\text{—}CH_2\text{—}NH_2 + CO_2 \text{ or}$$

$$R\text{—}CH(NH_2)COOH + H_2 = R\text{—}CH_2\text{—}NH_2 + H\cdot COOH.$$

Both amine and acid production may proceed simultaneously, the preponderance of one or the other reaction being dependent on the type of organism involved.

Aerobic organisms, especially fungi, can carry out oxidative deamination:

$$R\text{—}CH(NH_2)COOH + O_2 = R\cdot COOH + NH_3 + CO_2.$$

The products formed by biochemical decomposition of proteins include ammonia, carbon dioxide, amines, fatty acids, alcohols, aldehydes, phenol, indole, skatole, methane, and sulphuretted hydrogen.

Other Nitrogenous Compounds.

Non-protein nitrogenous compounds are also subject to biochemical action. Hecht [9, 1935] believes that the resistant nitrogenous substances such as faecal matter, of bottom organisms especially, may constitute a main source of petroleum. Trask [17, 1932] concludes that most of the loss of nitrogen does not take place until after the burial of the sediments, and there is a tendency for the relative amount of the resistant nitrogenous complexes to increase with age. *B. cellulosae dissolvens* decomposes cellulose very quickly in the presence of faecal matter as a source of nitrogen, giving ethyl alcohol, carbon dioxide, hydrogen, acetic and butyric acids (Waksman [18, 1927]).

Fats and Fatty Acids.

Fats are hydrolysed by micro-organisms to the fatty acids and glycerol, the latter then being used to form methane. Some believe that fatty acids resist subaquatic anaerobic decay, but Neave and Buswell [12, 1930] observe that anaerobic bacteria capable of decomposing fatty acids are widely distributed in nature. The adipocere examined by Ruttan and Marshall [13, 1917] was found to consist mainly of saturated acids, being constituted as follows:

Palmitic acid 67·52%, stearic acid 3·3%, oleic acid 5·24%, *i*-hydroxystearic acid 9·48%, θ-hydroxystearic acid 6·32%, stearin and palmitin 1·21%, olein 0·16%, unsaponifiable matter 0·87%, calcium soaps 4·41%, protein 0·665%, ash 0·578%, humus and undetermined matter 0·25%.

Free fatty acids may combine with metallic ions to form soaps in the sediments. The insoluble soaps in sediments are recovered only with difficulty, and little is known of the quantity present. Much of the inflammable gas from sewage arises from greases and soaps. McKenzie Taylor [11, 1928] has shown the anaerobic biochemical degradation of stearic and palmitic acids under a sodium-clay cover, and Thayer [16, 1931] carried out bacterial decompositions on the sodium salts of a series of organic acids: propionic, *n*-butyric, *i*-butyric, *n*-valeric, *i*-valeric, *n*-caproic, *i*-caproic, heptylic, lauric, palmitic, margaric, and stearic, with the production of carbon dioxide, hydrogen, and methane (within the limits of experimental error) only, and no determinable amount of unsaponifiable matter was left in the liquid.

Brooks [3, 1934] suggests that coorongite seems to be a product resulting from two different changes in fatty acids; one takes place in the presence of excess of air giving oxidation and polymerization of the unsaturated fatty acid. The other involves the loss of the carboxyl group of the acids and their polymers under anaerobic conditions.

The main fatty acids found in sediments by Trask [17, 1932] were cerotic ($C_{26}H_{52}O_2$), montanic ($C_{28}H_{56}O_2$), melissic ($C_{30}H_{60}O_2$), and caproic ($C_6H_{12}O_2$).

Carbohydrates.

According to Hackford [7, 1932] protobitumen is a partially reduced carbohydrate, which on further or total reduction yields oils. Fucosan, a polymer of fucose, is a constituent of the cell wall of marine algae. Acid hydrolysis of *Laminaria digitata* extracts gave fucose, which formed algarite (pure protobitumen), and a series of unstable polyhydric fatty acids which readily lost part or all of their oxygen to give hydrocarbons. At the same time the ethereal sulphonic esters broke down, yielding sulphuric acid which accelerated the hydrolytic process, and the unstable tertiary amines formed decomposed to give oil. In support of this mechanism he has found tertiary amines in oils, and the decomposition products of algae in natural oils and seepages. Bitumens from seepages have been hydrolysed to sugars, and sugars have been found in the water accompanying oil. Trask reports pentoses, pentosans, and glucose from the Lake Maracaibo deposits. In parenthesis, it is noteworthy that the prolonged boiling of sugars with dilute acids leads to the formation of a somewhat ill-defined substance known as humus; cf. hasemanite, coorongite, and phlobaphenes. Humus bodies are generally of an acid character, dissolving in alkalis to form brown solutions.

The action of acids on pentoses produces furfural (Gortner [6, 1929]). Hydrogen and methane seem to be produced directly from sugars by anaerobes (Waksman [18, 1927]), and Tarvin and Buswell [15, 1934] found the fermentation of dextrose to give methane and carbon dioxide with intermediate butyric, propionic, formic, acetic, and lactic acids, the last two acids also having been obtained from pentoses and pentosans by Fred.

Anaerobic decomposition of cellulosic matter gives carbon dioxide and fatty acids through methane or hydrogen fermentation. The evolution of gas ceases unless the acid products are neutralized. Many bacteria can live on cellulose, and such forms have been found in Grozni oil-well waters. Hackford suggests that decomposition of the cellulosic constituents of algae may give furfural and phenols. The peridineans have 40% of cellulose in their bodies, and with diatoms form the two main groups of

marine plants which, aided by sunlight, are able to produce organic from inorganic matter.

Both cellulose and hemi-cellulose can undergo enzymatic hydrolysis to sugars.

Lignins.

Lignins are fairly resistant to bacterial attack and may be slowly transformed to humus substances. It is necessary to distinguish the bacterial destruction of lignin from that of the contained pentosans and probably proteins. Trask found that the relative amounts of lignin-humus complexes showed an increase in 4 metres' depth of burial. Soil humus or 'humic acid' may contain 10% of material soluble in ether and alcohol (dihydroxystearic, oxystearic, lignoceric, and other acids).

Hasemanite, asphaltic though not a true fossil asphalt, occurs in some swamps close to the sea, and Haseman [8, 1921] believes it to be formed in the sediments from percolating ulmo-humic acids which are precipitated by sea-water. It is said to be found surrounding asphalt and contains tannic, ulmic, lignitic, humic, azo-humic, and azo-silico-humic acids.

Tannin.

Tannin is hydrolysed by acids to a variety of products, one of which is nearly always a sugar and another a hydroxy derivative of the aromatic series (usually an acid) (Gortner [6, 1929]). Heating with dilute acid gives solid, amorphous, insoluble 'phlobaphenes', as well as sugars, gallic and ellagic acids. These phlobaphenes are formed by any process tending to cause the tannin to lose water. Chemically they are relatively inert, and occur in nature only in association with tannins.

Waxes.

These, the esters of mono- (or in some cases di-) hydroxy alcohols or sterols with certain of the higher fatty acids, are more difficult to saponify than oils and fats which are esters of glycerol, and are very resistant to alteration, showing little change with age.

III

Conditions of Biochemical Action.

Trask finds that the absence of oxygen from the overlying waters is not absolutely essential for the preservation of organic matter in sediments, and it is not certain that completely anaerobic conditions are necessary for the production of methane.

Protein-splitting enzymes are most often active in an alkaline medium (Zinsser and Bayne-Jones [19, 1934]), and McKenzie Taylor used an alkaline medium, obtained by hydrolysing sodium-clay which gave an impermeable cover with consequent anaerobic conditions, and also neutralized the toxic acid products of the bacteria. Thayer's attempts to accelerate biochemical decompositions by varying the *pH* value were inconclusive, but nearly all his cultures were found to be alkaline, the more active having the lower *pH* values. Increasing the *pH* value inhibited the action. On the other hand, Hackford found his extracts of *Laminaria* to develop *Cladothrix dichotoma* and become acid due to free sulphuric acid, and carried out acid hydrolysis to form oil.

IV

Biochemical destruction of petroleum can occur, for there are certain bacteria capable of utilizing petroleum, paraffin, vaseline, benzene, naphthenes, phenols, cresols, &c. Lipman and Greenberg [10, 1932] have obtained a coccus or cocco-bacillus from petroleum from a depth of 8,700 ft. which can decompose petroleum completely to carbon dioxide. The action only seems to take place at the oil-salt-water contact, so it is unlikely to be of importance as far as large bodies of oil are concerned, but for oil globules disseminated in water, biochemical destruction may be extensive. Hence, if oil originates as scattered globules in water, there may be serious losses from the time of origin until it is accumulated into large bodies with relatively small areas of oil-salt-water contact, or until all the salts or other active constituents essential to the destructive reaction have been removed from the vicinity.

V

Thus it appears that methane is formed commonly by bacterial decomposition of organic matter, and is often accompanied by carbon dioxide. Hydrogen is sometimes produced. McKenzie Taylor records 'gaseous paraffins' from tributyrin under anaerobic conditions, but does not identify them. Ginsburg-Karagitscheva, using bacteria from oil-wells, reports the production of unsaturated gaseous hydrocarbons with methane from egg white, and from gum, acetate, and lactic acid the gases evolved had a flame indicative of unsaturateds. In discussing fats, Waksman states that Bach and Sierp have shown that under anaerobic conditions, carbon dioxide is split off and fatty acids change to hydrocarbons. Hence, omitting Hackford's work involving acid hydrolysis though with initial bacterial action, although there are hints about the formation of higher hydrocarbons, methane seems to be the only hydrocarbon proved to be produced in quantity by biochemical activity in the laboratory.

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SECTION 4

DISTRIBUTION OF PETROLEUM

THE STRATIGRAPHICAL DISTRIBUTION OF PETROLEUM

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I

Origin

DEPOSITS of oil or natural gas occur in practically all geological formations from Quaternary to Cambrian. In many more localities indications exist that the sediments at one time contained hydrocarbons which have become dispersed but have left their traces. This even holds true for pre-Cambrian and other crystalline rocks, in so far as they are sedimentary, but were changed by metamorphism (graphitic slates and schists, as occur in New Brunswick and in the Skelleftefjeld, in northern Sweden, and notably veins of graphite, which originally were veins of asphalt, such as are known from Ceylon).

There is a fundamental difference between primary deposits, in which the bitumen originated, and secondary deposits, where oil or gas accumulated after migration. Nearly all commercial oil deposits are in this latter class. No secondary accumulation, naturally, is possible unless primary bitumen is present in appropriate vicinity, in 'source rocks'.

Unfortunately much disagreement still exists concerning the most fundamental problem, namely *the origin of petroleum and natural gas.* Two main questions are involved: (I) the nature of the source material, and (II) the time and method of conversion and accumulation of this material into pools of liquid or gaseous hydrocarbons.

Most petroleum geologists believe that our commercial deposits of **oil and gas are exclusively of organic origin,** but again, unfortunately, there is a wide divergence of opinion both as to the types of organisms which have contributed the organic matter, and as to the nature and time of the transformation of this primary organic matter into petroleum. The existence of nitrogen derivatives and the optical activity of petroleum are strong indications of organic origin. Observation, moreover, shows that oil is practically always associated in some manner with sediments which contain abundant organic carbonaceous material. Differences of opinion exist as to the original organisms, some advocating vegetable, others animal material; some consider macro-organisms, like fishes and molluscs, dying occasionally in vast quantities, as the main contributors; others believe micro-forms, notably the plankton, to be the chief source. Much confusion has been caused by the concentration of research on kerosine shales and bogheads, which, although they may contain up to 70% in volatile matter, have never been known to be a source rock for commercial deposits of liquid oils in nature, however rich they may be in *fixed* bituminous matter. This can only be expelled by distillation. Some have thought that there exists a relationship between petroleum and coals, but modern views strongly hold that the coal-measure facies is adverse to the formation of free liquid bitumen. Evidently we must distinguish fundamentally between adsorptively *fixed* 'polybitumen', and *free* 'kerogen' (Mrazec, Krejci-Graf). The first is stable, the other, under certain conditions, is able to migrate. Some oil shales (for instance the Esthonian Ordovician kukersite) contain both kinds of bitumen, others, 'coal-oil shales', bogheads (Utah), only contain fixed polybitumen. In the earlier literature this important distinction is not made; in Germany *both* substances are referred to as 'Polybitumen', in English treatises, however, as 'Kerogen'.

The writer's own view has been arrived at after consideration of worldwide research work on modern marine sediments, executed, in part under his guidance, by P. D. Trask, and the recent independent work of K. Krejci-Graf and others. He has formed the opinion that the source rocks of commercially important accumulations of petroleum belong exclusively to two related classes of sediments: (1) those of the more or less '*Euxinic*' *facies*, typically present to-day in the Black Sea, which has clearly occurred locally in the sea throughout all geological time, and (2) sediments of a moderately *saline facies*, where the sea bottom was covered by water of a strong saline concentration. Both facies have this in common, that organic life (which may be exceptionally prolific under these circumstances) is confined to the upper horizons of more normal water, whilst the deeper and notably the bottom layers of water are more or less devoid of oxygen and in the extreme phase contain poisonous admixtures which exclude life on the bottom ('benthos'). In consequence all organic sediment (chiefly derived from plankton) is preserved from attack by the numerous scavengers which abound on all normal sea-bottoms, and becomes fossilized. In the present Black Sea, with a depth exceeding 2,000 metres in places, we have an extreme case. Here only the upper 50 metres of water contain sufficient oxygen to support life; in addition, all the deeper water, below 100–200 metres, is poisoned by sulphuretted hydrogen, liberated by sulphur bacteria. The black sediment contains from 23 to 35% of organic matter, and is devoid of any living thing, except anaerobic bacteria and ciliates. In the muds of normal seas, in the most favourable places for the accumulation and preservation of organic matter, Trask has never been able to find more than 7% of organic matter, and this was very exceptional (in deep sheltered troughs in the Channel Islands region off the coast of California). The average quantity of organic matter among recent sediments, as indicated by Trask's study of nearly 2,000 samples from many parts of the world, is 2·5%. Pelagic sediments were found to contain very little organic matter, not in excess of 1·5% (diatomaceous ooze of the Antarctic Sea; in the Atlantic and Pacific Oceans it is only half this amount). It is the exceptional, relatively rare circumstance that bottom life is sufficiently reduced or even excluded, which permits the formation of rocks sufficiently rich in organic material to be considered as source rocks of petroleum.

It would not seem necessary that such a high concentration of organic matter is reached as now exists at the bottom of the Black Sea. We know prolific oilfields where no source rocks of similar concentration can be identified (cf. P. D. Trask: Proportion of Organic Matter converted into Oil in Santa Fe Springs Oilfield, California, *Bull. Amer. Assoc. Petr. Geol.* 245–57 (1936)). The true Euxinic facies, however, is to be distinguished from the sometimes still more highly organic, often also marine, but mostly

coastal, Gyttja facies, also a sediment deposited under a restricted, but not excluded, oxygen supply. Here bottom life, although in a restricted number of species, is still actively present. True shallow-water Gyttja-sediments, however, never seem to cause petroleum deposits, but oil shales (algal gyttjas) and, in their highest organic concentration, boghead or cannel coals. The evolution is different. The presence of oxygen has prevented the preservation of porphyrins, notably from algal chlorophyll; gyttjas are richer in nitrogen and also in bromine. A modern occurrence of this facies exists prominently in the embayments along the coasts of Denmark.

True Euxinic sediments are exclusively marine, and generally a deep-water facies. There is no bottom life; chlorophyll porphyrins are preserved; they are poorer in nitrogen and bromine, but are distinguished by a concentration of such elements as Va and Cu (respectively 0·05 and 0·01%). At the present geological epoch the Euxinic facies is restricted to few secluded deep-sea basins, like the Black Sea. Because we still live in a moderately glacial period, when the earth's poles carry ice caps, there is active circulation of cold, oxygen-bearing polar water in the depths of all open oceans. There have been periods, for instance the Ordovician-Silurian, when this was not the case, and convection currents of oxygen supply in oceans were much reduced. As a consequence Euxinic environment was much more prevalent, even in widespread oceanic seas.

We find undeniable evidence of a more or less complete Euxinic facies in many geological formations. Well-established instances are: the black, sulphurous pre-Cambrian slates of northern Sweden; the widespread, dark graptolite-shales (a Palaeozoic planktonic organism) of the European and American Ordovician and Silurian; the black bituminous shales and limestones of the Upper Devonian and Lower Carboniferous (Culm) in the geosynclines and foredeeps of the chains of the Variscan orogenic cycle of North America and Europe; the Kupferschiefer of the west European Permian; several horizons of the Mesozoic and the Tertiary in the outer zones of the Alpide chains all over the world (for instance, the Oligocene and Cornu beds of Roumania). A very notable instance is the Late Tertiary of the Caucasian region, when the Black Sea extended much farther, with the same Euxinic environment as we find now; the oil deposits of Baku, &c., are derived from these source rocks. As stated, a present-day example is the now much-reduced Black Sea. These rocks are black sulphurous, pyrite-containing muds; if the facies is very pronounced, fossils are rare and confined exclusively to siliceous or chitinous remains of floating organisms, mostly small plankton forms, which are largely devoid of any shell or skeleton, fish scales, brachiopods which float attached to seaweed (Lingula, &c.), or buoyant shells of cephalopods. Lime shells are absent: calcareous matter is dissolved under these conditions. Source rocks of the saline class are found in deposits of concentration basins, before (or after) deposition of actual rock salt, at a time when strong salt solutions prevailed at the bottom, but the less salty upper layers of the water supported life. It is not necessary that the stage of precipitation of actual salt was ever reached; the cycle may have been interrupted. Concentrated brines are not only adverse to life, but they also prevent convection currents and access of oxygen to the deeper layers of water. The latter is the real cause of the preservation of organic matter, much more than concentrated salinity. These saline source rocks are generally dark bituminous dolomites and gypsiferous shales (*Stinksteine*). They are known especially from the Permian and Triassic salt basins of the American Mid-Continent and of Europe.

II

A. Conversion

The time and method of the conversion of the primary organic material to oil and gas is still obscure. It is evident that some fatty material may be deposited contemporaneously with source sediments, but it is very uncertain that any of this has the properties of petroleum. The conversion may be effected in various ways. Bacteria probably play an initial role; however, it has not yet been demonstrated that bacteria, either aerobic or anaerobic, can produce liquid hydrocarbons, except by their action on amino acids, in which case the resulting product is a small amount of benzene. The influence of elevated temperatures and pressures induced by deep burial or mountain folding, or both may be important. Experiments have indicated that the conversion of organic matter into free, soluble bitumen is a reaction not solely dependent upon temperature, but is also a function of time. However, there may be a critical temperature (under 150° C.?) below which no distillation will occur, no matter how long the time involved. The presence of chlorophyll porphyrins in many bitumina is an indication of a low-temperature history of petroleum. Petroleums contain several other types of constituents which are more easily decomposed by heat than the hydrocarbons or fatty acids. The presence of optically active constituents is also evidence of a low-temperature history. Shearing-pressure and high radial axial pressure experiments on supposed source rocks have yielded conflicting results, possibly because many of these experiments were made on oil shales and even coals, materials containing only fixed polybitumen, which is never known to be associated with commercial oil-deposits in nature. Experiments at the Colorado School of Mines, applying pressures as high as 200,000 lb. per sq. in. for 68 days, and even 250,000 lb. per sq. in. for 20 days, to Esthonian and Colorado oil shales, failed to produce any free oil. It would be interesting to continue similar experiments, not with oil shales, but with black marine bituminous shales of Euxinic facies. Even in bituminous marine shales the remains of higher plants are always preserved as coal, but lower vegetable forms, like algae, are in part converted into free kerogen. Hydrogenation stimulated by natural catalysis and even alpha radiation have also been suggested to play a part in conversion, but this is still unproven. It appears, however, that there is a general absence of free hydrogen in rocks of the earth's crust. The fact, however, that hydrogen is so easily migratory, still much more than the also very rare helium, may explain why it has never been preserved. That alpha radiation affects gaseous hydrocarbons and produces a condensation of lower into higher members, up into the region of liquids and solids, has been demonstrated.

The fact that oil, and especially gas, are so readily susceptible to dispersion would suggest that present-day accumulation in old rocks, notably in the Early Palaeozoics, closely overlain by old land surfaces, does not date from such very remote time, but is of comparatively recent formation. There may be periodically recurring events which induce the liberation of liquid petroleum from still unspent source rocks, which would thus be able to generate successive crops of oil or gas. These events, probably, are complex, but must generally be in the nature of a slow 'cracking' of

primary bitumen resulting from biochemical processes; especially when the beds have become supersaturated, beyond the amounts which can be fixed by adsorption, free bitumen may be induced to migrate either by compaction or by orogenic stresses. It seems highly probable that the very saline water, with excess of calcium, iodine, and bromine, sometimes also potassium, which is regularly found associated with oil-pools, is no fossil sea-water, but a segregation product of the original organic material: organisms which have concentrated these rare constituents of sea-water. Pollution by waters of another origin may, of course, frequently have happened.

That diagenetic processes are involved in the conversion seems indicated by the Ordovician kukersite of Esthonia, which may contain from 30 to 50% of free kerogen. In this region pressure by overburden has never been considerable, high temperatures caused by deep burial have not occurred, and orogenetic stresses have been absent. As a result of these same conditions Palaeozoic coals are still in the lignite stage, and we find plastic, entirely recent-looking clays even of Lower Cambrian age; evidently nothing has occurred here that could convert kerogen into freely migrating petroleum.

B. Migration and Accumulation

Traces of bitumen and oil are of very frequent occurrence in sediments; commercial accumulations, however, are rare and restricted to relatively very small areas, which are determined by favourable structure. The three products of the original organic source material evidently segregate, and migrate according to their specific gravities, oil and gas seeking the higher levels in a reservoir stratum, water the lower ones. Beds containing commercial oil can be of every petrographic description or geological age, provided they possess porosity. They may be marine or continental sediments, sands or sandstones, gravels or conglomerates, oolitic or otherwise permeable beds, even porous igneous rocks or their derivatives (Texas). Evidently these petroliferous strata are only secondary reservoirs into which free bitumen has migrated. In many cases typical source rocks are known to underlie oil-pools at greater or lesser depth; in most other cases there is reason to assume their presence, whilst reservoir beds are mostly of a nature which excludes primary (autogenous) petroleum.

Where a stratigraphical sequence contains numerous porous strata a structural oilfield will generally contain a number of superimposed 'oil sands'. The general section of the pool will present a more or less conical platform of petroliferous horizons, narrower towards the top and laterally wider towards the base. The productivity in each individual 'sand' is dependent on its petrographic aptitude as a reservoir, but in general those nearer to the source beds will be richer. The oils will differ vertically, in a manner that can be explained either as a consequence of filtration or through oxidation in contact with surface waters, or otherwise. Gas not associated with or dissolved in oil will mostly be characteristic for the upper 'sands'. Many Californian oil-pools, and also those in the Baku region, on account of the great thickness of the local petroliferous section, offer perfect examples of typical infiltrated oil-platforms (for instance, Ventura, Signal Hill, Apscheron Peninsula); the same rules, however, with more or less perfection, apply to practically all major oilfields.

In the writer's opinion, migration, in consequence, must be assumed to occur chiefly in a vertical direction, towards the surface, in accordance with density and the gradient of pressure. That downward migration may also occur, at least over a short vertical distance, is proved by the lower zone of the Playa del Rey oilfield in California. This zone rests directly on metamorphic (Franciscan) schist, having no possibilities as a source for oil, but is overlain by a 100–200-ft. bed composed of the most highly bituminous shale found in any oil section in the United States (Trask). The successive 'oil sands' of a petroleum deposit may be separated by major unconformities (Oklahoma City, &c.), or even by great overthrust faults (Borislaw), in consequence of which petroleum impregnation affects beds which originally have been deposited many miles apart, and vertically traverses two or more overthrust slices (cf. the article on Oilfields in Folded Rocks). Sometimes the supply of oil appears to have stopped at an unconformity and not to have extended to younger beds. There are cases where displacement of beds along faults or even by folding have not, or not yet, been followed by a readjustment of the oil deposits along the new structural lines, but where oil and gas still remain concentrated in accordance with older structure. This suggests that conversion and migration of petroleum is sometimes almost contemporaneous with sedimentation, or that in other instances it may start at some time considerably later than the deposition of the source sediments; that it is not induced or even influenced by every orogenic displacement of beds, and that it may, or may not, be renewed, and may occur in different successive crops which are widely separated in time.

Many geologists have accepted lateral migration over considerable distances, from regional synclines or depressed basins towards structural highs, or from areas of intense compression towards such as are less affected by orogenic forces. The writer is willing to concede lateral migration over relatively moderate distances, notably from the flanks towards the crest of individual anticlinal or monoclinal structures, but denies the possibility of long-distance regional migration, because resistance would be excessive and observations prove that it has not actually occurred, except to a very limited extent. The main paths of migrating petroleum must be small partings and fissures, which abound in all rocks and sections and are generally directed more or less vertically upward. Even impervious clays and rock-salt have been observed to contain fissures, actually carrying oil, asphalt, ozokerite, and other derivatives of petroleum. Sandstone dykes, as we know them from Roumania, Baku, California, Burma, and even from Huronian shales near Cleveland (Ohio), also bear witness of ascending water, carrying fine sand and mud, even erratics. These materials were probably driven by natural gas, as escaping to-day from mud volcanoes. Aptly these phenomena have been called 'sedimentary volcanism'. It is by no means necessary to consider only faults and wider fissures, although tnese also may play a role. Considerable faults are mostly impervious, because plastered by clay produced by friction they cannot act as conduits, and have a sealing effect.

In accordance with the prevailing upward direction of migration we find that, in general, asphaltic oils decrease in density with depth (Roumania, Gulf Coast); paraffin oils, however, increase in density with depth (Roumania). Often asphaltic oils (oxybitumina) overlie deeper paraffin oils. There are, however, exceptions to this scheme. Oxidation must be assumed to induce polymerization, but the latter appears the major factor in the formation of asphalts. Filtration and the adsorption of the larger molecules, which will also occur in narrow fissures, explains the decrease in density

of paraffin oils towards the surface. Asphaltic deposits and inspissated oil of a previous cycle of migration may occur at or near old buried land surfaces along unconformities, and be overlain by paraffin oils in younger strata, filled by a later cycle of continued or renewed migration of petroleum (Oklahoma City and Lucien oilfields, Okla., where these asphalts (grahamite) occur in the top of the Ordovician). There is no relation between asphaltic or paraffin oils and absolute depth, and both kinds of crude may occur in reservoir rocks of any age; only access of oxygen (now or at some earlier period) seems to count, but there is some indication of the influence of calcium-salts on the formation of asphaltic products low in oxygen. The writer is aware that this conclusion is contested by B. T. Brooks and A. Treibs on account of the presence of chlorophyll porphyrins in many asphalts, derivatives which are decomposed by oxidation. There are asphalts low in oxygen, which may have another history.

Although migration may in some oilfields (California, Baku) be a relatively recent event, it remains nevertheless a slow process. At Ceptura (Roumania) we know an instance of recent folding, to which the oil accumulation has not yet adjusted itself, still occupying locations evidently previous to the latest displacement of the strata. Water, however, migrates more rapidly than the oil and precedes it (as is observed in the flooding practice for the revival of oilfields). This explains the prevalence of salt-water sands, intercalated between oil sands in a petroleum deposit.

For further details regarding the very important, though yet far from fully cleared subject of migration, reference should be made to the several papers contained in the symposium *Problems of Petroleum Geology* (Amer. Assoc. of Petroleum Geologists, 1934) and the recent publications by F. M. Van Tuyl, B. T. Brooks, K. Krejci-Graf, St. Zuber, and O. Stutzer. They contain a critical discussion of many conflicting views which have been expressed, and in several cases an extensive bibliography of references.

III

The actual stratigraphic distribution of petroleum reservoirs in the various oilfields of the world is, as already described, a very wide one; these reservoirs are not the autogenous source rocks, but secondary accumulations. The source rocks may sometimes be almost contemporary deposits (Los Angeles, Baku), at other times they are of widely different age.

A. Palaeozoic Oilfields

These are widespread in North America, but this is possibly only a consequence of more extensive exploration. In the Appalachian oilfields of the eastern States, in Michigan, in Indiana and Illinois, over the entire Mid-Continent, as far south as central Texas, also in the Rocky Mountain region, in Alberta and in Ontario in Canada, petroleum occurs, sometimes very prolifically, in well-consolidated sandstones, and often in limestones of Palaeozoic age, ranging from the Permian down even into the Upper Cambrian.

1. In the **Cambrian** a little gas occurs in New York State; some notable quantities of asphalt are reported from Upper Cambrian rocks of western Australia.

2. **Ordovician** petroleum is produced in Ohio and eastern Indiana (Trenton dolomite), in Illinois (Middle Champlainian), in Kentucky and Tennessee, in Michigan (Ordovician and also Devonian), in Kansas, Oklahoma, and central Texas (Ordovician 'Wilcox sands', and Cambro-Ordovician Arbuckle limestone). Ordovician petroleum now constitutes the major supply and reserves for the production in the States of Oklahoma and Kansas.

3. **Lower Silurian oil** is found in the Medina and Guelph dolomites of Ontario.

4. **Middle and Upper Devonian and Lower Carboniferous** petroleum is produced from sandstones and some limestones in a number of oilfields along the western foothills of the Appalachian Mountains, the bulk in the Lower Mississippian and Upper Devonian, at or near the unconformable contact between these strata: in New York, Pennsylvania, West Virginia, Ohio, Kentucky, Tennessee, and then again from limestones in the Rocky Mountain region, in Alberta and Montana, Wyoming (Lower Mississippian Madison limestone); in Michigan there is also production from Mississippian rocks (Berea).

On the Eurasian continent the oil of the Timan Range (Ukhta) occurs in Upper Devonian strata.

5. **Upper Carboniferous to Lower Permian** petroleum is produced in America from the upper horizons of the Appalachian oilfields, but notably all over the mid-continent: in Illinois, Missouri, Kansas, Oklahoma, north-central Texas, in the Rocky Mountain region, in Utah, Colorado, and Wyoming (Tensleep formation).

In Europe: from the western flank and the foreland of the Ural Mountains (Tschussovaija, &c.)., possibilities exist in north central Europe (Westfalia, Holland, &c.) and in England (Hardstoft).

Several indications are reported from central Asia which are probably Upper Palaeozoic.

6. **Upper Permian** petroleum is produced abundantly in North America from dolomites and limestones in the Great Salt Basin of west Texas and eastern New Mexico.

In Europe, to a limited extent in Germany (south of the Harz Mountains in Thuringia; Volkenroda, &c.).

B. Mesozoic Oilfields

These again are common and prolific in North and Central America: in the Cretaceous of the Rocky Mountains region from Alberta to Mexico, and in east Texas and northern Louisiana–southern Arkansas; in California Cretaceous production is insignificant.

7. **Jurassic** petroleum is produced in small quantities in North America: in Alberta and Montana (Ellis formation), and in Wyoming and Colorado (Sundance formation).

In Europe: in several Jurassic horizons on flanks of the north German salt-domes.

In Asia: in Middle and Upper Jurassic strata of the Emba region, north-east of the Caspian Sea (some oil has also been found there in Permian and Lower Cretaceous horizons).

8. **Cretaceous** petroleum is produced abundantly in North America along the eastern foothills and in intramontane basins of the Rocky Mountain system in Alberta, Montana, Wyoming, and Colorado; in the Cretaceous oilfields of the Gulf Basin in southern Arkansas, Louisiana (Sabine Uplift), and east Texas (Balcones Fault zone and monoclinal structures along the western flank of the Sabine Uplift; east Texas oilfield, Rodessa, and other Woodbine sand and Trinity (basal Cretaceous) oil-pools); in the State of Mississippi the Jackson field is producing from Cretaceous chalk.

In Central America the prolific oil-pools of Mexico produce from the Cretaceous along the eastern foreland of the Sierra Madre Oriental.

In South America: in Bolivia and the Argentine, along the eastern flank of the main Cordillera.

In Europe: in the Wealden formation of northern Germany, on the flank of some salt-domes; some of the Carpathian oil of Galicia is produced from Cretaceous reservoir rocks. Indications of petroleum exist in the Lower Cretaceous and Jurassic of southern England.

C. Tertiary Oilfields

Tertiary oil is still much more common all over the world in many, not infrequently extremely prolific, oilfields.

In North America may be cited: California, producing abundantly from Miocene and Pliocene sands of great thickness, and in minor quantities from Oligocene and Eocene; the Lower Rio Grande Basin of south Texas and northern Mexico (Eocene: Fayette, Yegua, and Cook Mountain formations); the salt-domes in the coastal zone of the Gulf Coast Basin of Texas and Louisiana (from Miocene to Eocene horizons).

In South America: the oilfields of Venezuela, Columbia, and Trinidad; the eastern Argentine, and Peru.

In Africa: the oilfields of Egypt (saline Miocene in the Erythrean Rift).

In Europe: the oilfields along the outer edge of the Carpathian arc, from the Vienna Basin, through Galicia, to Roumania, all produce from several horizons of the Miocene and Pliocene (occasionally from Lower Tertiary in Galicia), sometimes even from Quaternary beds; the oilfields of the Rhine Graben in Alsace (Pechelbronn) are in Oligocene; the important oilfields along both flanks of the Caucasus Mountains, from Maikop and Grozny (Miocene) to the Apscheron Peninsula in the east (several horizons in the Pliocene); beyond the Caspian Sea the oilfields of Cheleken and Nepthe-dagh also produce from the Pliocene.

Farther east in Asia oil is known in the Ferghana Basin (folded Eocene); in western Iran (Arabistan) petroleum is profusely produced from the Lower Miocene Asmari limestone; in Iraq (Kirkuk) the oil is more or less of the same age. In Burma and India the oil sands range from Middle Eocene to Lower Miocene. In the Netherlands East Indies the oil-bearing formations in Sumatra are of Lower Pliocene and Upper Miocene age (Middle and Lower Palembang series); in Java, Miocene; in east Borneo, Miocene to Pliocene; in Tarakan, Pliocene; in New Guinea, Pliocene.

In Sakhalin Island and in Kamtchatka the oil in Pliocene.

THE GEOGRAPHICAL DISTRIBUTION OF PETROLEUM

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In this article only accumulations of free hydrocarbons (oil, gases) and their oxidation products, such as asphalt, are considered; not the absorbed or otherwise fixed hydrocarbons in oil shales, boghead coals, or similar minerals, which only give off liquid oil and gases on heating.

Since the primary essential for the formation of commercial oil-pools is the accumulation of a suitable sedimentary sequence, it is obvious that the geographical distribution of oilfields must be closely related to zones of movement and special sedimentation. Mineral oil is a migratory fluid, made still more mobile by the presence of gases, dissolved under high pressure, and its accumulation into deposits of commercial value is only a stage in a considerable cycle of events. In geological history oil-pools are not only formed, but also become lost; are subject to dispersion of the oil; or the reservoir strata containing the oil may be demolished and carried away by denudation.

Oil-pools range in age from the Lower Palaeozoic to the Pleistocene, but their existence is always subject to the same fundamental law concerning genesis, accumulation, and preservation.

The distribution of commercial oil deposits, that is, the existence of 'petroliferous provinces', suggests regional affinities, not only as to source rocks, but also as to opportunities for accumulation and preservation. Since the uncertainty of the third factor becomes greater with the age of the deposit, the occurrence of pools in the older, especially the Palaeozoic, rocks is rarer than in the younger Upper Mesozoic and Tertiary sediments.

In consequence no commercial occurrences of oil are found in regions occupied by crystalline pre-Cambrian rocks, in ancient continental nuclei, or in the crystalline and metamorphic central zones of the great mountain systems of the earth. They occur preferably in two distinct structural provinces: (1) *the foredeeps of the folded mountain belts* and (2) on *mobile epicontinental shelf-regions.*

1. Oil provinces occur in those parts of geosynclines where conditions for the deposition of source sediments were favourable, but where posterior deformation through mountain folding, uplift, and subsequent denudation were not adverse to preservation of oil-deposits. This was especially the case in the so-called 'foredeeps', the depressions which almost always parallel the front of all larger folded chains, and where the sediments of relatively deep water have not been affected too seriously by the mountain building forces, and oil-deposits have not been destroyed, either by denudation or by metamorphism. Foredeeps of this nature occur in front of chains, formed by all three major orogenic cycles which have affected the crust since Cambrian time: the Early Palaeozoic (Caledonian) cycle, the Late Palaeozoic (Variscan) cycle, and the Late Mesozoic-Tertiary (Alpine) cycle. It is evident that oil-pools connected with the youngest of these cycles must be the more frequent, and those of the oldest extremely rare, not on account of the conditions which caused their formation, but because their chances of preservation diminish with their age. The areas occupied by the older orogenies have very frequently been affected again by movements connected with later cycles, not necessarily folding, but at least sufficient faulting and vertical displacement to cause the destruction or escape of these fluids.

2. In the unfolded solid and more *tabular forelands* of the folded mountain belt, or in tabular regions overlying older folded, but since solidified areas, that cannot be called forelands, there also occur relatively mobile regions which are affected mostly by vertical movements of considerable magnitude. Some regions are inclined to repeated and sometimes almost continuous uplift, accompanied by denudation, causing the absence or at least a very restricted development of sediments. Other regions have a tendency to subside through prolonged periods, and in consequence have been frequently submerged under epicontinental seas, and have accumulated considerable sediments of numerous geological formations. In these latter areas conditions may have occurred which were favourable to the formation of source rocks, and structures may have been formed which permitted accumulation and preservation in suitable reservoir beds (cf. the article on the Stratigraphical Distribution of Petroleum). The area affected by such movements may be of a wide regional character, like the great Mesozoic and Tertiary North Sea–German Basin of north-western Europe, the Palaeozoic region of the north American Mid-Continent, or the Caspian region of Russia. In other instances only a limited block may subside, like the petroliferous Rhine Graben of Alsace, or in tramontane basins overlying the peneplained surface of the Variscan chains of Europe (Thüringen). Frequently such subsiding regions contain saline deposits at certain stratigraphic horizons, which, under sufficient load, cause curious intrusions of the plastic saline rocks, known as salt-domes, as in the Gulf Coast of North America, in north-western Germany, and in several other regions. Since the saliferous facies may be accompanied by abnormally active deposition of source rocks, such salt-domes are not infrequently the site of oil-pools.

I. EUROPE

A. Foredeep Oil-pools

(*a*) **Alpine foredeep pools** occur along the outer zone of the Carpathian loop, from the Vienna Basin through Galicia, into Roumania. In the frontal zone along the Alps numerous indications of petroleum or oil gases exist, notably in western Switzerland, but commercial pools have not yet been discovered. The same conditions continue in the outer zones of the Pyrennean, Apennine, and Dinaric chains. Exploration, however, is still continuing and may be successful. Both in Italy and in Albania minor oil-pools have been found. Along the northern front of the Caucasus these indications are also found, but here they are accompanied by a string of important pools from Maikop, along Grozny, to the Baku region, which extends across the Caspian into Cheleken, and eastward into Asia (Neftjanaja Gora and Bujadagh in Turkmenia).

(*b*) **Variscan foredeep pools** have not yet been discovered in Europe, but here also, indications suggest the possibility

of pools having been preserved along the outer front of the Permo-Carboniferous chains: showings in the English Midlands (Hardstoft), in eastern Holland (Corle), and in Westfalia (Munsterland), and then again along the entire western front of the Timan and Ural Mountains (from Uktha and Tschussowskije Gorodki in the north to Sterlitamak in the south). The latter region is reported to be very similar to that of the Atlantic (Appalachian) oilfields of North America.

(*c*) In the region of the European Caledonides only a very few small showings have been reported in Scotland.

B. Foreland Pools and Pools in other Plateau Regions

(*a*) In **the basin of north-western Germany** several so far not very important and irregular oil-pools exist on the flanks of salt-domes in Hannover, and small seepages, gas-wells, or asphalt deposits suggest possible occurrences over a wide area, doubtlessly also connected with upthrusts of salt. On one of these production has been obtained recently at Heide in Holstein.

(*b*) In **the Hungarian Basin** and the depression of **Transylvania,** within the Carpathian loop, there occur fairly prolific gas deposits, and recently some oil was found in Hungary. These originate in Tertiary basins in the hinterland of the Carpathian loop, overlying peneplained older folds.

(*c*) A series of important showings, already partially developed into very promising oilfields occurs in **the Caspian Emba region**; some 300 salt-domes are reported in this area, of which several have been drilled successfully.

(*d*) Within narrow Tertiary graben-depressions, which traverse the old Variscan folds along **the Rhine and the Rhone Valleys,** are situated the oilfield of Pechelbronn in Alsace, and showings in Baden, and in the Rhone Valley (Ambérieu); this is repeated in graben-zones in the northern part of the French Central Plateau (Cortal).

II. NORTH AMERICA

A. Foredeep Oil-pools

(*a*) **Tertiary Chains.** Important oil-pools have been developed, and almost yearly new ones are being discovered, along the outer zone of the Late Cretaceous-Early Tertiary Rocky Mountains, from Alberta, in Canada, through Montana and Wyoming, into Colorado. A younger belt of late Tertiary mountains lies farther to the west and is accompanied by the famous oil-pools of California and eastern Mexico.

(*b*) Bordering the **Late Palaeozoic chains** petroleum deposits have been preserved in quantity. A series of oil-pools parallels the outer front of the Appalachian mountains from New York and Pennsylvania, through West Virginia, Kentucky, and Tennessee, with still some showings in Alabama. Modern petroleum production had its beginning in Pennsylvania.

(*c*) No oil-pools are known connected with the Early Palaeozoic (Taconic) orogeny in New England.

B. Foreland Pools and Pools in other Plateau Regions

A very important Palaeozoic oil province occupies the entire central tableland of the North American Mid-Continent. Generally these are extremely gently-warped structures, the dip increases slightly in the deeper Early Palaeozoic horizons, and is often accentuated by faults. In this class can be grouped the oilfields of Michigan and Ohio, of Illinois, Kansas, and Oklahoma, and farther south of Central and West Texas and eastern New Mexico (oilfields of the great Salt Basin). In South Oklahoma and North Texas the fields are in an intermediate class, being affected also by the folded Late Palaeozoic chain of the Wichita Mountain System. Then again the great Cretaceous-Tertiary depression of the Gulf Coast plain, from South Arkansas to Louisiana, East and South Texas, abounds in very important oilfields of this type, partly in the Cretaceous (Balcones belt, East Texas field, Sabine Uplift, Rodessa) partly connected with a great many productive salt-domes in the Late Tertiary formations along the coast, or with other Tertiary structures along the lower Rio Grande in the foredeep of the easternmost Sierra Madre ranges.

Apart from Europe and North America, the other continents have been much less explored for the occurrence of oil deposits. In South America and parts of Asia important oil provinces are known, and indications are encouraging that there is little doubt that sufficiently undiscovered deposits of commercial importance must exist; the opposite is the case with Africa and Australia. This is especially true if we consider the results obtained in North America by active and systematic exploration during the 35 years of the present century. It seems necessary, therefore, to mention the geographical distribution not only of the known oil-pools in these regions, but also to indicate briefly the major possibilities of reserves in this vast territory.

III. SOUTH AMERICA

A. **Foredeep Pools** of great importance occur all along the north-eastern branch of the South American 'Alpine' Cordillera Oriental and Cordillera de Merida from Ecuador, through Colombia and Venezuela, as far as Trinidad.

Several oil-pools and many more potentialities exist along the little explored eastern front of the main Cordillera in Bolivia and Argentina, as far south as Tierra del Fuego.

B. Oilfields within more **tabular regions** are those in the Argentine pampa of Rivadavia and in the coastal plain of Peru.

IV. ASIA

Asia has many oil provinces of importance and contains vast regions, very little explored, from which occurrences and indications of petroleum are reported.

(A) Along the front or inside of the 'Alpine' chains a number of oilfields and indications occur. The principal ones are:

(1) The Ferghana district of South Turkestan with notable oil-pools on Eocene folds. The entire area along the eastern shores of the Caspian, and along the northern rim of the chains which link the Elburs Mountains to the Hindukush, seems petroliferous; favorable Tertiary folding is indicated in the subsurface.

(2) The famous pools along the south-western front of the Iranian Mountains in Iraq (Mesopotamia) and Iran; and several promising indications within the mountain chains in Asia Minor and North Iran.

(3) The pools along the western front of the Arakan-Yoma and Naga-Chin Hills of Burma, and the southern front of the Garo-Khasi-Mikir Hills of India.

(4) The oilfields along the eastern side of the Barisan Mountains of Sumatra; this belt continues through Java and Madoera, and farther east, with various indications in the smaller Soenda islands.

(5) Oil deposits on Sakhalin Island (especially the east coast), and similar indications in the Kamtchatka Peninsula, with additional possibilities in the other island arcs of the western Pacific Ocean.

B. As oilfields within more unfolded regions may be mentioned the Bahrein Islands on the Arabian coast of the Persian Gulf, and the oilfields along the east coast of Borneo.

Many occurrences of oil are reported from the almost unexplored interior of Asia, most of which are probably within the frontal zones of **Late Palaeozoic (Altaid) chains,** although many observations suggest intercalated folding of the Alpine cycle in these same regions. Some of these oil deposits may also occur within unfolded sediments filling intramontane basins. The detailed geology of this vast region is still mostly unknown. The following may be mentioned:

(1) Oil seepages and ozokerite are reported on the southern flank of the Tien Chan Mountains in East Turkestan, in the region of Kutcha.

(2) Important oil seepages, exploited by natives, are said to be reported from the northern flank of the Nan Shan Mountains in West Kan Su.

(3) Supposedly abundant and widespread oil seepages are reported in North Shen Si and the Ordos country (Mongolia) within the big bend of the Hwang Ho River.

(4) The previously known saline oil and gas occurrences in Szetshwan, particularly 'the world's oldest Corefield' north-east of Fu Shun, near Tseliutsin. These showings, however, are very poor, and the natural exposures, from Cretaceous to Permian inclusive, give little encouragement.

Indications of oil are also reported from the provinces of Jehol and Liaoning in North China. Asphalt and tar seepages are also reported from the Dsungarian Gobi desert, near Telli-Nor lake.

From Siberia U.S.S.R. geologists report oil indications spreading from the extreme north (Taimyr, and the mouths of the Lena River) to as far south as the shores of Lake Bajkal. Of this vast and inaccessible region little precise information is so far available. Alpine chains circle the Archaean Siberian Shield to the north and east; great bundles of Late Palaeozoic folds, with Alpine intercalations, build up most of China and Mongolia.

V. AFRICA

The only regions of Africa of which so far there is precise information as to oil are situated near the mountains along the Mediterranean in the north-west, and in Egypt, in a downfaulted block along the Gulf of Suez. The first group belongs to the class of foredeep deposits connected with the Alpine chains of the Rif Mountains (Djebel Tselfat in Morocco, in front of the Gibraltar-Rif arc). Those in Egypt are tableland deposits connected with saline structures. Similar deposits may occur elsewhere in North Africa.

Indications of oil have been reported from Angola.

VI. AUSTRALIA

With the exception of New Guinea and New Zealand, the Australian Tertiary deposits are not affected by the Alpine cycle of folding. From New Guinea and New Zealand, however, indications of petroleum are reported. Most of the Australian continent is tableland. Evidences of petroleum are conspicuously absent. The only area which is actually producing a small quantity of oil is at Lakes Entrance in Victoria (Oligocene, resting on granite). This suggests the possibility of some occurrences in the major basin, which is largely filled with marine tabular Tertiary sediments. In the Palaeozoic sequence asphalt is conspicuous in association with Upper Cambrian rocks, but from the later Palaeozoic and the Mesozoic formations no seepages are known, with the exception of some wet gas near Roma, in South Queensland, and in Central Queensland.

OIL AND GAS IN THE UNITED STATES

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I. Introduction

AT the time of writing the world seems to be amply supplied with petroleum and natural gas. The nation which uses the most oil certainly appears to have no cause for worry when a single field in the eastern part of Texas has the potential capacity of furnishing nearly one-half the amount consumed by the whole nation. At the present moment one billion barrels in round numbers is the amount needed annually by the United States, and the East Texas field, flowing for a short time without restrictions, produced in excess of one million barrels per day. However, a brief examination of the figures presented in the closing paragraphs of this section will reveal that at the present rate of extraction our supplies would last only a few decades. In addition, the inevitable decline in production of settled fields will tend to lower the amounts immediately available.

For these reasons the search for new supplies is going on feverishly. Simple means of finding new pools have been exhausted. A deeper and more fundamental understanding of the problems of oil occurrence is needed to ferret out and suggest the location of such pools. The only way in which a better conception of the peculiarities of oil accumulation may be gained is by the study of known fields.

Those familiar with the oilfields of the world will grant without hesitation that the oilfields of the United States afford the most fruitful source of information. Their areal extent is great and the distribution of petroliferous materials in a stratigraphic respect is unequalled elsewhere. Furthermore, the types of structural traps and other kinds of traps are exemplified at different points under differing sets of geological conditions, so that their importance may be evaluated. Producing horizons of varying age, of varying thickness, and of varying lithology may be compared. During the last 15 years special studies have been carried on by hundreds of geologists in the United States to bring out certain critical relationships. The study of well-cuttings both from the standpoint of lithology and of fossil content is revealing information of great value. Analyses of water and brines from shallow and deep horizons are being made on an extensive scale. Comparative studies of oil gravities from similar horizons and from varying depths have thrown some light on fundamental problems. Fortunately, and this fact is acknowledged by all who have an interest in these matters, the results of such studies have been made available by the liberal attitude of oil company officials. A vote of thanks is also due to the broad-minded policy of the officers of the American Association of Petroleum Geologists, by whose untiring efforts an enormous amount of detailed information has been published.

It would be a mistake, however, to assume that the path of the oil-finder has been made smooth and easy. Despite the great accumulation of data on origin of oil, its migration and accumulation, there probably never was a time in the history of petroleum exploration when new pools were so difficult to locate. Perhaps the simplest way to demonstrate this fact is to point out the known characteristics of each petroleum province in the United States. It may then be possible to point out in what untested portions of the province similar conditions exist.

Tectonic Classification.

In recent years it has become apparent that structural features of a certain magnitude have exerted a controlling influence on oil accumulation. These in turn are subordinate to, and genetically related to, other features of a greater magnitude which may be called tectonic elements. In accordance with these principles the author some years ago proposed the *Tectonic Classification* of oilfields in the United States. Since that time further drilling has strengthened the validity of the classification. In the following sections each petroliferous province based on such tectonic elements will be treated as a unit. Each of the provinces has certain outstanding characteristics which will be briefly summarized in order to give the reader a perspective for the many details which follow.

Appalachian Geosyncline Province. By far the greater portion of the oil and gas found in the Appalachian province is stored in sandstones of fine-grained texture. These extend through a vertical thickness of approximately 8,000 ft. and range in age from Pennsylvanian to the base of the Silurian. The most prolific sands appear about the middle of the section in the Lower Mississippian and the Upper Devonian strata. In certain parts of the province, as, for instance, in eastern Kentucky, limestones assume importance.

In the eastern part of the province the gas was trapped in rather long, narrow, and fairly high anticlines. Farther west the influence of anticlinal structure is present, but masked by the variations in porosity and permeability of the oil-containing sandstones. In fact, the more western part of the producing territory is characterized by almost total lack of structural control except that of homoclines. Two exceptions to this generalization are due to prominent intra-basin structures, the Burning Springs anticline and the Irvine-Paint Creek fault and uplift.

Cincinnati Arch Province. The Cincinnati Arch is a positive tectonic element which separates the Appalachian geosyncline from the Eastern Interior Coal Basin. In the Lima-Indiana district of the northern portion oil is typically associated with the Trenton limestone of Ordovician age. Selective solution by ground water provided the limestone with porous zones in which the oil accumulated. In the Cumberland Saddle district, which lies in south central Kentucky astride the axis of the Cincinnati Arch, conditions are somewhat different. For one thing the producing horizons are younger, ranging from Mississippian to Silurian. On the other hand, the nature of the producing horizons is similar because they are predominantly porous limestones and are saturated where unconformable relations exist with overlying strata.

Michigan Basin Province. In the Michigan Basin oil has been found chiefly in Middle Devonian and Lower Mississippian formations. The former are limestones and the latter sandstones. Gas has been derived principally from still higher levels in the Mississippian system. Erosional

unconformities associated with narrow anticlinal trends account for the oil accumulations. Scattered wells in many parts of the Southern Peninsula have outlined the trend and general nature of these anticlinal zones, and it is reasonable to suppose that many new pools will be found.

Eastern Interior Coal Basin Province. The oil-pools in north-western Kentucky, western Indiana, and in Illinois have much in common. The producing horizons are mostly of Upper Mississippian (Chester) and Lower Pennsylvanian age. Sandstones predominate, but a few limestone horizons are important locally. One intra-basin structural feature stands out because of its striking relation to the most prolific pools in the province, the La Salle anticline. East and south-east of this anticline the relation of structure to production is obscure. There oil accumulation is probably due to slight relief of strata along planes of unconformity. West of the La Salle anticline the oil accumulations seem to be definitely related to small domes and anticlines. On the anticlines there is some indication of unconformities associated with the producing horizons. This same relationship is very evident on the La Salle anticline, although there the rapid variation in the nature of the clastic sediments tends to prevent the demonstration of this fact.

Western Interior Coal Basin Province. The oilfields of Kansas and northern Oklahoma have certain similarities which point to a congenital relationship. Oil and gas are predominantly associated with two stratigraphic zones, one in the Lower Pennsylvanian and the other in the Ordovician system. In the former sandstones stand out as the main reservoir rocks, but in the latter calcareous rocks divide honours with the sandstones. In all horizons the influence of unconformable relations at the producing level is strikingly apparent. Two types of traps are typically developed. One of these is the low angle, unsymmetrical anticline, faulted at depth. This kind of trap is especially found along the western side of the producing area in Oklahoma and throughout the central portion of the Kansas fields. A great wedge-shaped fault block of comparatively low relief was pushed up in Early Pennsylvanian time, and the most productive pools found in the two States appear in long zones on the traces of the buried faults marking its limits. East of this intra-basin structural feature oil accumulations are associated chiefly with homoclinal structure or slight modifications thereof. There the up-dip decrease in porosity of sandstones has played the leading role. West of the intra-basin fault-plateau no important oil-pools have been found in Oklahoma. In Kansas, however, numerous small pools have been discovered, and at the present time new ones are being found almost monthly. These are mostly related to structurally high points along the trend of buried outcrop zones in the pre-Pennsylvanian strata. Inasmuch as these zones parallel the axis of the buried Barton Arch of post-Devonian age, they tend to line up along north-west lines. Complications are introduced by the narrow belts of Early Pennsylvanian deformation which cut across the older structural feature with a north-east trend.

Wichita–Amarillo Province. A series of fault blocks, partly buried and partly exposed in low mountains, cuts across the middle of the Mid-Continent region with a north-west trend. Oil- and gas-pools are associated with these tectonic elements in a number of ways. Some are located over buried fault blocks as the Panhandle fields of north-western Texas, the pools between the Arbuckle and Wichita Mountains in southern Oklahoma, and some of the pools in northern Texas on the so-called Red River Uplift. Some pools, notably those of southern Wichita County and northern Archer County, Texas, do not seem to be directly related to such pronounced structures. Although arranged in belts parallel to the Red River Uplift, they occur in strata which are only slightly deformed. The age and nature of the producing horizons vary somewhat in the three districts of this province. In southern Oklahoma and northern Texas the oil is stored predominantly in sandstones of Middle Pennsylvanian age (Glenn and Cisco). In the Panhandle district, on the other hand, the chief producing horizon is a limestone of Lower Permian age. There, furthermore, gas is far more abundant than oil. It should perhaps be emphasized that the influence of the faults mentioned above is not apparent at the level of the producing horizons unless the anticlinal structure be considered a reflection of the buried faults.

Bend Arch Province. A very broad arch with low flanking dips extends southward towards the central Texas mineral region. The scattered pools along its axis derive their oil from porous limestones of Early Pennsylvanian age or from sandstones of Pennsylvanian age. Oil traps of several kinds account for the accumulations. Small domes of moderate relief, terraces, and 'noses' have been found in the most important pools. Elsewhere homoclinal structure with pinching sands and limestones of varying porosity have served to trap the oil.

Gulf Embayment Province. In the fields of southern Arkansas, Louisiana, east and south Texas, the producing horizons are almost exclusively sandstones, although certain limestones are important locally. Only Comanchean, Cretaceous, and Tertiary formations are involved, but the range in thickness through which they are distributed is very great. Each district in the province shows characteristic structural features to account for the oil accumulations. The Balcones Fault district, as the name implies, is characterized by several zones of short faults arranged *en échelon.* The oil is trapped on the upthrow side of the faults. In the Sabine and Ouachita Uplifts district several kinds of traps have been found. Some pools are on small high domes which may or may not show subsidiary faults. Others are closely associated with pinching sands that lie above prominent unconformities. Some are in porous limestones close to unconformities. In south Texas and south Louisiana small domes with very great relief have served to trap the oil and gas. These are the well-known salt-dome pools. Other productive areas are associated with sand lenses of shoreline type in which differential porosity is the controlling factor.

West Texas Province. A great structural basin lies west of the Bend Arch. It has one outstanding intra-basin structure on which all important pools are located. The main producing horizon is a dolomitic limestone of Permian age called the 'Big Lime', but important production has also been found in a limestone of Ordovician age (one pool only). The reason for oil accumulation seems to be high structural relief on the central platform coupled with great porosity in a limestone below an unconformity.

Rocky Mountain Province. The largest petroliferous province in the United States extends from Montana through Wyoming and Colorado into New Mexico. Sandstones of Middle and Lower Cretaceous age contain most of the oil and gas. Locally, important amounts of oil have been found in Comanchean, Jurassic, Permian, Pennsylvanian, and Mississippian formations. The Permian and Mississippian horizons are limestones which produce from porous

zones along an unconformity. Ninety per cent. of the pools are located on anticlinal folds in which the strata dip steeply. These folds in turn are arranged in zones *en échelon* fashion close to the rims of structural basins. Geophysical data indicate that small subsidiary fault blocks, genetically related to the mountains bounding the basins, underlie the anticlines. If this should be corroborated by future exploration, the chances for additional pools are very slight. Some intra-basin structures have been discovered, as, for instance, the Baxter Basin dome in the middle of the Green River Basin and the Rangely dome in the Uinta Basin.

Pacific Geosyncline Province. The oil-pools of southern California are concentrated in four structural basins, in which structural and stratigraphic similarities are marked. Tertiary sands produce the oil, and up to date the Pliocene has accounted for the larger portion. Miocene sands are important in the Santa Maria district and the San Joaquin district. Oligocene sands are important in the Ventura district. One striking feature of all these sands is their great thickness and complete saturation.

As regards structural control a striking similarity to the Rocky Mountain province may be pointed out. Here also the predominant trap is the anticline. Furthermore, the arrangement of the anticlines and domes in nearly straight lines or zones above pronounced fault lines is significant. A third similarity appears in the steep dip on the flanks of the anticlines.

Migration and Accumulation of Oil.

A careful comparison of all details of oil occurrence in the various provinces of the United States leads to certain definite inferences. It appears reasonably certain that oil in calcareous reservoir rocks has not migrated any considerable distance. In many cases it can be shown that no migration has taken place at all. In some districts the underground channels have been developed on such a large scale that veritable subterranean caverns were produced. In these there has been some migration and gravitational separation of the fluids.

In sandstone reservoirs migration has been somewhat more extensive, but even here it may be measured in miles and not tens of miles. The path traversed by petroleum and gas has been primarily between bedding planes in the same reservoir rocks. Some cases are on record which plainly indicate vertical migration along fault planes. However, the inference is not justified that such vertical migration is common. In both types of migration gas has travelled much farther than oil. In fact, there is some indication that gas may have travelled tens of miles. This appears to be the explanation of the fact that gas-pools frequently occur in the high peripheral structures which bound petroliferous basins. A case in point is the Appalachian province, which is almost completely surrounded by gas-pools.

Origin of Oil.

The most difficult problem in petroleum geology concerns the mode of origin of the oil. It is still too early to make confident assertions on this important point. The straws in the wind lead to the conclusion that plant matter contributed most of the oil and that animal matter was decidedly subordinate. Furthermore, it appears that certain conditions favoured organic accumulation and petroleum generation. One of the fundamental concepts is that the locus of accumulation was an area close to sea-level. Such an area would be the gently sloping sea floor parallel to the shoreline of the time. A similar one would be provided by slightly submerged islands or archipelagos. The latter explains why important oilfields are so commonly found on intra-basin structures, as, for instance, the La Salle anticline, Barton Arch, Burning Springs anticline, &c. Even the Cincinnati Arch would be an illustration of the same situation because it was an intra-basin structure during Early Palaeozoic time.

Environment for Oil Accumulation.

If the foregoing inferences prove to be correct, then the environment most favourable for oil accumulations may be deduced. Three primary and equally essential factors determine this environment. One of these is *porosity*, for without openings large enough to contain oil and gas no accumulation can take place. Subcapillary openings provide storage space for petroleum and gas, but do not produce commercial pools, for the reason that the permeability is too slight to permit free flow of the fluids. For that reason oil shales and bituminous shales do not make oil-pools. Openings in siltstones (Bureau of soils classification 0·005 to 0·05 mm.), on the other hand, are large enough to make commercial gas-pools possible. Still coarser sediments (fine, medium, and coarse sands) in which the grain size ranges from 0·05 to 2 mm. may contain commercial accumulations of oil, but Nutting reports [3, 1934, p. 826] that most producing oil sands examined lie between 0·07 and 0·21 mm.

The second factor in the environment of oil-pools is the *relief* of the porous reservoir rock. This is commonly called a 'high' in oilfield terminology. A 'high' may be a portion of deformed strata which is elevated above the rest of the structure, or it may be a topographically elevated rock unit. Hence anticlines, domes, the upthrow side of fault blocks, &c., produce favourable 'highs'. On the other hand, the truncated edges of inclined strata which form topographic relief features may be just as favourable under certain conditions of cap-rock relations. The same effect is provided by the up-dip termination of porosity in a homoclinal reservoir rock.

The third factor is the local abundance of organic source material. In the absence of definite knowledge of the constitution of such material no further elucidation is possible. The inferences regarding migration, however, lead us to believe that such source material must have been present within or in immediate contact with the reservoir rock at the time of its burial and before the cap-rock was formed over it.

Future Reserves of Oil.

In the past nearly all estimates of future oil reserves in the United States have erred in being too small. It is hoped that the estimates given below will also prove to be too small. In most cases they should be looked upon as conservative. By projecting the production curves of nearly exhausted fields and groups of fields it is possible to anticipate their total ultimate production in some provinces and in some districts. On the basis of a close study of drilling results between producing areas it is possible to reach a reasonable conclusion regarding the possibility of undiscovered pools. By adding the two sets of figures a satisfactory prediction of future production can be made. From the following summary it appears that the future reserves for the whole country total at least 13 billion

barrels and that the total ultimate production will exceed 30 billion barrels.

Province	Production to end of 1935	Reserves	Total ultimate
Appalachian . .	1,740 million bbl.	500 million	2,300 million
Cincinnati Arch . .	500 „ „	65 „	600 „
Michigan . . .	55 „ „	250 „	300 „
Eastern Interior . .	465 „ „	100 „	565 „
Western Interior . .	4,400 „ „	2,500 „	6,900 „
Ouachita–Amarillo .	1,150 „ „	500 „	1,650 „
Bend Arch . . .	354 „ „	125 „	500 „
Gulf Embayment . .	3,000 „ „	3,500 „	6,500 „
West Texas . . .	750 „ „	1,500 „	2,250 „
Rocky Mountain . .	500 „ „	500 „	1,000 „
California . . .	4,460 „ „	3,000 „	7,500 „

II. Appalachian Geosyncline Province

The Appalachian geosyncline province is the oldest and best-known province in the United States. It was named from the fact that the producing area corresponds to the central portion of the Appalachian geosyncline which extends from New York State southward into the State of Alabama. The producing area includes south-western New York, western Pennsylvania, eastern Ohio, western West Virginia, and eastern Kentucky. Geologically the area is limited on the east by the strong Hercynian folds of the Appalachian Mountain system. On the west the Cincinnati Arch forms the natural boundary. The northern end is closed in by the Laurentian shield and parallel bands of Early Palaeozoic strata. (See Fig. 1.)

Stratigraphy.

The Appalachian geosyncline existed from earliest Palaeozoic time until the close of the era. Therefore every system of that era is represented from the Cambrian to the Permian inclusive. As a rule each system is very thick in the eastern part of the geosyncline because of the proximity of the sediment-yielding land mass (Appalachia) and much thinner towards the west. The thicknesses given in the table on this page are averages for the oil-producing area only.

It will be seen from the table that the Permian system does not contain oil- or gas-producing sands. The Monongahela contains the highest producing sand, the Goose Run, which yields a little oil near Marietta, Ohio. In the Conemaugh there are five sands of which the First Cow Run is the most important, having produced considerable quantities of oil and gas in south-western Pennsylvania and in south-eastern Ohio. The three gas sands which appear in the Allegheny in south-western Pennsylvania are unimportant, and the same applies to the Macksburg sand of south-eastern Ohio. In West Virginia, however, the upper 'Gas Sand' has furnished considerable quantities of gas. The Salt sands of the Pottsville were so named because they contain much salt-water in Pennsylvania. In the adjoining portions of Ohio, West Virginia, and Kentucky some oil has been obtained from them. All sands of the Pennsylvanian system are interbedded with thin shales, limestones, and coals. In position they are usually referred to the Pittsburgh coal which marks the base of the Monongahela.

The Mississippian system may be conveniently divided into three portions, the Mauch Chunk red and green shales, the Greenbrier (or Maxville) limestone (Ste Geneviève and St. Louis in Kentucky), and the Pocono or Waverly clastic series. On account of the prominent unconformity at the top of the Mississippian, the Mauch Chunk is thin in the petroliferous area and disappears from the section in south-eastern Ohio. The Maxton sand appears at this unconformity either as reworked rubble at the base of the Pennsylvanian or residual material at the top of the Mississippian. Much oil and gas have been obtained from it

Stratigraphy and Producing Sands in Appalachian Province

		New York		Pennsylvania		Ohio		West Virginia		Kentucky	
System	Formation	Thickness	Sand	Thickness	Sand	Thickness	Sand	Thickness	Sand	Thickness	Sand
Permian . .	Dunkard	..	..	1,000	..	400	..	800	..	..	..
Pennsylvanian .	Monongahela	..	..	300	..	250	Goose Run	200	..	..	..
	Conemaugh	..	..	600	Cow Run	450	Cow Run	600	..	..	..
	Allegheny	..	..	300	Gas Sand	250	Macksburg	150	Gas Sands	..	..
	Pottsville	..	..	200	..	400	Salt	500	Salt	800	Salt, &c.
Mississippian .	Mauch Chunk	..	..	1,000	..	100	Maxton	200	Maxton	200	Maxton
	Greenbrier	..	..	50	..	100	..	80	..	150	Big Lime
	Pocono or Waverly	..	..	1,000	Big Injun, Berea, Hundred-Foot	600	Keener, Big Injun, Squaw and Berea	350	Keener, Big Injun, Squaw, Weir, Berea	400	Keener, Big Injun, Squaw, Weir Berea
Devonian . .	Catskill	300	..	600	Gordon, Snee, Fourth, Bayard, &c.	800–3,000	'Ohio Shale'	600	Gordon, Fourth, Fifth, Bayard	100–700	Chattanooga
	Chemung	1,500	Bradford	1,100	Warren, Speechley, Tiona, &c.	„	„	800	..	„	„
	Portage	900	..	1,000	Kane, Elk	„	„	500	..	„	„
	Gen. Ham. Mar.	900	..	1,200	..	„	„	700	..	„	„
	Corniferous	150	..	80	..	600	..	400	..	60	Irvine, &c.
	Oriskany	20	Gas	20	Gas	20	Cambridge	25	Gas	..	..
Silurian . .	Salina	600	..	250	..	600	..	..	..	..	..
	Niagara	180	..	150	..	500	..	375	..	50	Big Six
	Clinton	80	..	300	..	150	..	..	..	..	..
	Medina	1,100	Gas	100	..	350	Clinton	300	..	..	..
Ordovician . .	Cincinnati	600	..	600	..	1,000	..	..	..	..	..
	Trenton	900	Gas	600	..	500	..	..	..	..	..
	Beekmantown	200	..	..	..	..	..	..	..	..	..
Cambrian . .	Potsdam	40	Gas	..	..	..	..	..	..	..	..

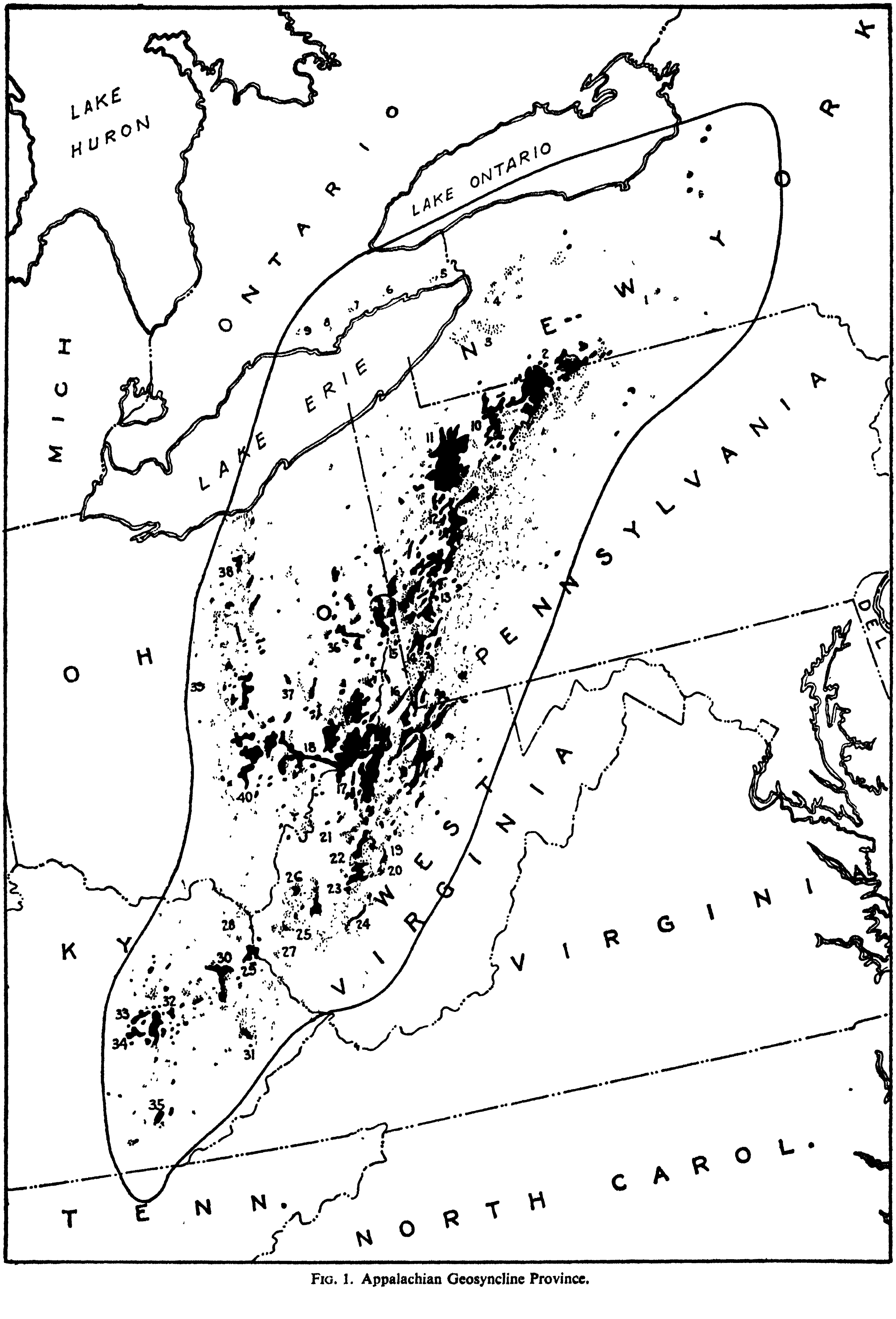

FIG. 1. Appalachian Geosyncline Province.

in south-eastern Ohio and a small amount in eastern Kentucky.

The most productive sands of the Mississippian system appear in the Pocono or Waverly division. The Big Injun produces over a wide area bordering the Panhandle of West Virginia. The Squaw and Weir sands are more local but quite prolific. The Berea sands cover the widest area, since they extend over all of eastern Ohio and north-western Pennsylvania as well as south-western Pennsylvania and adjacent parts of West Virginia and Kentucky. The Murrysville and Hundred-Foot sands are included in the Berea sand group by Torrey. The Hundred-Foot is the equivalent of the First Venango, made famous by I. C. White's reports on north-western Pennsylvania. The Thirty-Foot sand, which lies close beneath the Hundred-Foot, is the equivalent of his Second Venango.

The Devonian system, consisting predominantly of drab-coloured shales contains twelve or more important sands. In the Catskill the Gordon is the most important, as it produces from a large area in western Pennsylvania and West Virginia. The Fourth and the Fifth are large producers from a somewhat more limited area. The Bayard, Gordon Stray, and Elizabeth sands produce mostly gas. Another important group of sands are those of the Chemung division. They are limited to the northern portion of the Pennsylvanian fields. The Speechley, Tiona, Balltown, and Sheffield sands produce mostly gas, while the Warren and Bradford sands are large producers of oil. The Bradford sand also has produced the major portion of the oil and gas in southern New York. The Kane sands of the Portage division have produced enormous quantities of gas in north-western Pennsylvania. In the same area the Elk sands produce gas.

At the base of the thick body of Devonian shales lies the 'Corniferous' or Onondaga limestone. In Kentucky, where it lies unconformably beneath the Chattanooga shale, it is considered the most important producing horizon of oil. There it includes the Irvine, Ragland, and Campton sands. Beneath the limestone lies the Oriskany sand which has recently come prominently into the limelight. A number of gasfields in southern New York and northern Pennsylvania, as well as the Cambridge field in eastern Ohio, derive their gas from this formation.

The Silurian system consists of fine clastics and evaporites at the top, calcareous materials in the middle portion, and coarse clastics at the base. The latter contain gas sands (Medina) of importance in southern New York as well as the outstanding 'Clinton' sand fields of central Ohio. Gas has been produced in small quantities from the unconformable top of the Niagara limestone in Kentucky.

Rocks of Ordovician and Cambrian age come to the surface around the periphery of the producing area, but within it they lie at great depths. For that reason little is known at present about their possible productivity. In New York State some small gas-pools were found years ago in the area east of Buffalo in which the Trenton limestone contained the gas. Similarly, in the vicinity of Watertown (Jefferson County) gas was found in the Potsdam sandstone. These pools have long since been abandoned.

Relation between Structure and Production.

The prominent long, narrow anticlines so characteristic of the eastern Appalachians die out towards the west. They are still prominent in the gas belt which marks the eastern side of the producing area. The Warfield–Chestnut Ridge anticline very nearly forms the eastern boundary of these fields. Shorter and lower anticlines have been delineated by geologists west of it, but in general the producing area is characterized by a gentle regional dip towards the south-west of approximately 30 ft. to the mile. One striking exception is furnished by the Burning Springs anticline which trends nearly north and south and has great relief.

Some years ago the author prepared a map showing the oil- and gas-pools as well as the anticlines and synclines. This map indicates that about 60% of the pools are located upon or close to the axes of anticlines. In general the gas-pools show a closer relation than the oil-pools. In Pennsylvania the relation is closer in the north-eastern part of the producing area and less close towards the south and south-west. In West Virginia the relation is very obscure, except that very prominent anticlines, such as the Arches Fork, Burning Springs, and Chestnut Ridge anticlines, are somewhat more completely spotted with pools than the synclines between them. In Kentucky the pools are significantly alined with the Paint Creek fault zone and several cross folds. In Ohio the influence of the Burning Springs anticline is notable because the largest cluster of oil-pools occurs along its trend. A very striking zone of gas-pools through the centre of the State traces the zone in which the Medina sandstone comes to a feather edge on the Cincinnati Arch. Between these two there are numerous scattered oil-pools and gas-pools that appear to bear no definite relation to large structures.

The relations pointed out indicate that structural relief has controlled migration to some extent. Much gas and some oil have accumulated in elevated portions of the strata. Some of the gas and most of the oil have accumulated without regard to structure. In both cases the controlling factor has been the permeability of the reservoir sands. The author believes that the oil and gas originated at the same time that the reservoir sand was deposited. Pools formed where porosity and permeability conditions were favourable. Gas accumulated in sands with small porosity and oil in those with greater porosity. When folding took place some rearrangement of gas, oil, and water was possible where continuous porosity in the same sand existed. At the same time gas (being more volatile and needing only minute pore spaces) migrated from west to east towards the stronger anticlines. This sequence of events explains why only gas is found in the peripheral portions of the province. It also explains why gravitational arrangement of the fluids is found on the stronger anticlines, but not in areas where the dip is less than one degree. For, as Torrey [5, 1934, p. 466] points out, there are extensive areas in south-western Pennsylvania and portions of the adjoining States where certain sands contain mixtures of oil, gas, and water under conditions that preclude migration. He has also published many illuminating data on porosity and permeability conditions in various parts of the Pennsylvania fields.

The productive area in Pennsylvania is nearly 200 miles long and averages 60 miles in width (7·6 million acres). About 25% of the area is gas territory and about 15% oil territory (somewhat over 1 million acres). It has produced 900 million barrels of oil and almost 5 trillion cubic feet of natural gas. On this basis the per acre production is less than 1,000 barrels of oil. The largest pool, the Bradford pool, covering an area of 105,000 square miles, has a per acre production of somewhat over 2,600 barrels to the end of 1936. Based on present methods of extraction and exploitation it is reasonable to predict that the Pennsylvania fields will produce an additional 200 million

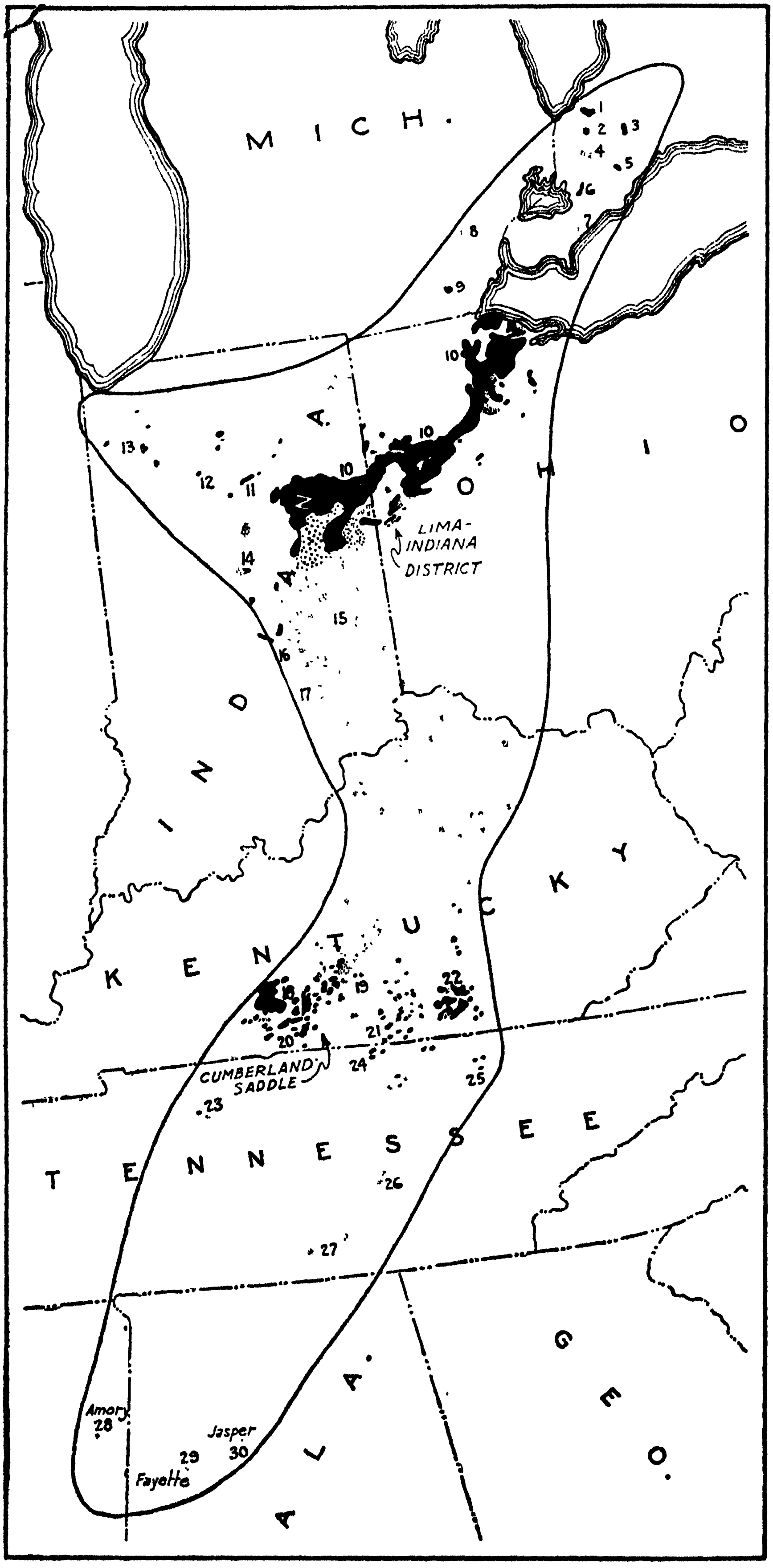

Fig. 2. Cincinnati Arch Province.

barrels before they are abandoned. For somewhat more optimistic estimates see Cathcart [4, 1935, p. 373].

The Pennsylvanian fields have accounted for slightly more than 50% of the total production of the province. West Virginia stands in second place with slightly less than 25% and a per acre production of somewhat over 500 barrels of oil. Ohio follows with about 11% of the total, while Kentucky and New York share equally in the remainder. Allowing for a total production of 1,740 million barrels to the end of 1936, it may be estimated that the reserves amount to about 500 million barrels for the whole Appalachian province.

III. Cincinnati Arch Province

The oil- and gas-fields of the Cincinnati Arch province are located in western Ohio, northern and eastern Indiana, central Kentucky, central Tennessee, north-western Alabama, and north-eastern Mississippi. Geologically they are related to the large broad geanticline known as the Cincinnati Arch. The axis of this positive tectonic element passes southward through the centre of Kentucky, Tennessee, into Alabama and Mississippi. Northward from Cincinnati it bifurcates, one branch passing through western Ohio into Ontario and the other through northern Indiana towards central Wisconsin. (See Fig. 2.)

Stratigraphy.

The names of formations used in this province are not uniform because different parts of the area involved were studied by different geologists at various times. It will be convenient, therefore, to divide the province into *districts* in which the nomenclature is similar. The most important district is the northern one usually referred to as the *Lima–Indiana* district. It is located in north-western Ohio and north-eastern Indiana. Pleistocene glacial deposits cover the older rocks to a large extent. Below the drift the drill passes through the Monroe formation of Upper Silurian age. The underlying Niagara and Clinton limestones are about 300 ft. thick and the Medina red shales average 50 ft. in thickness. The Ordovician Cincinnati shales are divided into the Richmond and Utica formations, the former being blue and the latter dark in colour. They are succeeded

by the oil-bearing Trenton limestone which, as the table shows, is approximately 750 ft. thick.

In those wells which have penetrated the Trenton a considerable difference in thickness is apparent. This fact, as well as the caverns and sinkholes at the top of the formation, indicates an erosional unconformity between the Trenton and overlying shales. During the period of erosion oil and gas formed in the solution holes and have remained in these traps ever since. Evidently three zones of porosity were produced, for oil has been found at three more or less distinct levels. The first and by far the most prolific lies within 50 ft. of the top of the limestone. As a rule drillers encounter a few feet of impervious rock which they term 'cap-rock', and below that a varying amount of porous 'rotten' rock. This upper producing horizon accounted for nearly all the oil and gas until 1900. The lower 'pays' in the Trenton have been of small importance, and this applies also to the other three 'stray' sands encountered at various times. They are the Clinton limestone, the Cincinnati shales, and the 'St. Peter' sandstone.

Stratigraphy and Producing Sands in Cincinnati Arch Province

System	Formation	*Lima–Indiana* Thickness	*Lima–Indiana* Sands	*Cumb. Saddle East* Thickness	*Cumb. Saddle East* Sands	*Cumb Saddle West* Thickness	*Cumb Saddle West* Sands	*Tennessee* Thickness	*Tennessee* Sands	*Ala.–Miss.* Thickness	*Ala.–Miss.* Sands
Pennsylvanian .	Pottsville	..	..	100	..	100	..	..	..	700	Fayette
Mississippian .	Chester	..	..	250	..	500	.		..	900	Hartselle
	Meramec	..	..	450	..	500	St. Louis	200	Glenmary	450	.
	Waverly	..	..	250	Beaver Creek	150	Beaver	200	..	170	.
	Chattanooga	..	..	25	..	50	.	100	..	30	..
Devonian . .	Corniferous	..	..	0	..	30	Corniferous	0	..	0	
Silurian . .	Monroe	160	..	0	..	0	..	0	..	0	
	Niagara	200	..	0	..	125	Niagara	0	..	250	
	Cl. and Medina	150	..	35	..	0	.	0	..	0	.
Ordovician .	Cincinnati	650	..	600	..	650	..	0	..	50	
	Trenton	750	Trenton	900	Sunnybrook	1,000	..	1,500	Sunnybrook	1,200	..
	'St. Peter'	20	.	?	..	?	..	.	..	..	..
	Canadian	400	..	..	..	.	..	..	..	..	..

The 'St. Peter' horizon is an interesting one and deserves further testing. From the meagre data available it seems to be the erosional detritus at the top of the Canadian limestones which has been discovered in many parts of eastern United States. In the early reports on the Indiana portion of the district sandstones of some thickness are mentioned at this horizon, but drilling in Ohio has failed to corroborate this.

Carman and Stout [5, 1934, p. 521] have brought out some interesting details regarding the structure of the Lima–Indiana district. Among them is the description of the fault which bounds the producing area south-west of Toledo. The fault trends nearly north to south and has a displacement of 200 ft. for 7 miles, beyond which it passes into a monoclinal fold. Production is obtained from both sides of the fault, but it is better from the down-thrown side.

Cumberland Saddle District. The undulations of the crest of the Cincinnati Arch bring into relief two prominent domes, the *Jessamine* and the *Nashville* domes. The former is located in north-central Kentucky and the latter in central Tennessee. The axis of the saddle between them trends nearly east to west in south-central Kentucky, through Cumberland County, and for that reason it has been named the Cumberland Saddle [8, 1930, p. 103].

Where the axis of the saddle crosses the Cincinnati Arch Ordovician rocks are unconformably overlain by Mississippian (Chattanooga) shales. Eastward and westward thin wedges of the Devonian Corniferous limestone, the middle Silurian Niagara limestone, and the lower Silurian shales and limestones appear in the sequence. On the east side of the axis the Chattanooga is overlain by the shales and cherty limestones of the Waverly, and in this formation practically the only important oil sands occur. They are not true sands, but porous limestones to which the name *Beaver Creek Sand* has been applied. The oil-pools are located in Wayne and McCreary Counties. Above the Waverly the Meramec limestones (Newman) and the Chester shales (Pennington) complete the stratigraphic sequence.

On the west side of the axis the Chattanooga shale, on account of its black colour, again serves as the best key horizon. Above it lie the Waverly (New Providence and Ft. Payne) cherty limestones and shales. Some oil has been found in eastern Warren County in the upper part of the New Providence in the so-called *Beaver Sand.* The overlying Meramec consists of the Warsaw, St. Louis, and Ste Geneviève limestones in ascending order. A few large wells found a mixture of oil, gas, and salt-water in porous layers near the base of the *St. Louis limestone*, especially in the Bowling Green field.

Below the Chattanooga there is a limestone of Devonian age which was evidently exposed to erosion for a long time because it is quite porous. Oil, gas, and water accumulated during the erosion interval in the openings so developed, and the *Corniferous* has proved to be the second most important horizon in the district. Some wells in the Moulder and Sledge pools came in for 1,000 barrels per day. Another erosional unconformity appears in the section between the Corniferous and the Silurian *Niagara* limestone. Actively circulating ground waters dissolved this formation to a great depth, for the oil-bearing cavities have been found as much as 100 ft. below the top. The pay zones appear at different levels in the limestone and vary from 1 to 17 ft. in thickness. This is the most important producing horizon in the western part of the Cumberland Saddle district and quite satisfactory quantities of oil have been secured from it in Allen and in Warren Counties.

Tennessee. The amount of oil produced from Tennessee to the end of 1935 is about 300,000 barrels. This has come from counties adjacent to the productive area of Wayne and McCreary Counties in Kentucky on the east side of the Cumberland Saddle. The most important producing horizons are porous zones in the Ordovician limestones

approximately equal in age to the 'Trenton' of the Lima–Indiana district. Some small oil- and gas-pools have secured production from the Ft. Payne division of the Waverly and from the Meramec (St. Louis) limestone.

Alabama and Mississippi. By extending the axis of the Cincinnati Arch under the cover of Cretaceous rocks in northern Alabama and Mississippi, it may be assumed that the small gas-pools of those States are related to it. The Fayette gas-pool of north-western Alabama has produced perhaps 200 million cu. ft. since 1909. It is derived from a sand in the Pottsville division of the Pennsylvanian system. The first commercial gas-well was drilled in Mississippi in October 1926 near the town of Amory, Monroe County. It was rated at 5 million cu. ft. per day. Subsequently several smaller wells were drilled in north-eastern Mississippi. The producing horizon is a sandstone in the Chester division of the Mississippian system which may be correlated with the Hartselle sandstone in which asphaltic residues have been found on the outcrop. The important producing area near Jackson will be described in § VIII.

Relation of Structure to Accumulation.

The outstanding cause for oil and gas accumulation in this province is the porosity of the reservoir rocks. The Lima–Indiana district has a number of large pools that are narrow, elongated, and have irregular fringing borders. These pools extend down the dip of the Cincinnati Arch a distance of 800 ft. from the crest in Delaware County, Indiana, to a point near Toledo, Ohio. In a general way they follow the zone where the flat dips on the arch give way to the rather steeper dips on the north and north-west sides leading down into the Michigan Basin. Evidently, the oil and gas are indigenous to the reservoir rock, and accumulation took place in solution channels before the capping shales were deposited. Intercommunication between the solution channels is indicated by the fact that gravitational separation has taken place in local areas.

In the pools of the Cumberland Saddle district porosity has also been the controlling factor. The important producing horizons are porous limestones subjacent to a prominent unconformity. The fact that oil, gas, and water mixtures are commonly encountered shows clearly the lack of migration. Evidently, the eroded edges of pre-Mississippian limestones furnished an ideal environment for the oil-producing plant matter.

Production Statistics.

Gas escaping along the Blanchard River first called attention to the natural resources of the Lima–Indiana district, and the records show that gas was used for illumination in Findlay as early as 1838. The first oil-well was drilled in 1885, and since then the district has furnished nearly 475 million barrels of oil. The production curve and the results of recent exploration indicate that the district is more than 90% exhausted, leaving a future reserve of less than 50 million barrels.

In the Cumberland Saddle district oil production began (as a by-product of the salt-boring industry) in 1819 with the drilling of the famous Beatty well. A gusher was drilled in 1829 in Cumberland County, but the commercial urge for intensive exploration did not come until 1860. Subsequently many small pools were discovered, and these accounted for a total of 20 million barrels of oil. Considering the peculiarities of oil occurrence in this district, it is not unreasonable to assume that 40% of the original reserves are still stored underground. However, the low per acre production, estimated by Hunter and Browning [4, 1935, p. 311] to be 700 barrels, will not encourage drilling within the near future.

IV. The Michigan Basin Province

The oil- and gas-pools of the Michigan Basin province are located in the Southern Peninsula of Michigan. The map, Fig. 3, indicates their location within the State. Geologically the producing areas are located on long, narrow anticlinal trends which pass across the basin from south-east to north-west. The most prominent one is the Howell–Broomfield trend which begins in township 1 N.—range 7 E., and can be traced to township 23 N.—range 16 W. Near the town of Howell drilling has revealed a fault with a throw of about 1,000 ft. (down to the west). This indicates that the whole trend as well as the more prominent parallel trends are probably located over deep-seated faults. Among the important anticlinal trends lying north-east of the *Howell trend* may be mentioned the *Greendale trend* on which the Porter, Yost, Mt. Pleasant, Denver, and Vernon oil-pools and the Clare gas-pool are located. The next pronounced trend is the *Port Huron–Saginaw trend* which is at present poorly defined. Still farther north-east lies the *West Branch trend* in Ogemaw County.

Stratigraphy.

The stratigraphy is outlined by means of a table which appears below. The highest formation consists of red coloured shales and gypsums with sandstone at the

Stratigraphy and Producing Horizons in Michigan Basin

System	*Formation*	*Thickness*	*Sands*
Pennsylvanian	Red Beds	100	..
	Pottsville	300	Parma (some gas in lenses)
Mississippian	Upper	300	Michigan (gas)
	Middle	300	Marshall or Napoleon (gas)
	Lower	1,200	Berea (oil at Saginaw)
Devonian	Upper	400	..
	Middle	400	Traverse (oil). Second most productive Dundee (oil). Most productive
	Lower	400	Detroit River or Monroe (oil) Sylvania (shows in Mason Co.)
Silurian	Cayugan	1,000	..
	Niagaran	400	..
	Medinan	150	..
Ordovician	Cincinnati	500	..
	Trenton, &c.	400	Trenton (shows in SE. Mich.)
	St. Peter	50?	..
	Canadian	150	..

base. They do not crop out extensively, inasmuch as the whole Southern Peninsula is more or less completely covered with glacial drift that in places exceeds 800 ft. in thickness. In the basal sandstones some gas has been found (Parma). Below the Pennsylvanian strata the unconformity so common in eastern United States appears in the sequence. Therefore the Upper Mississippian limestones, shales, and evaporites are missing in many places and over considerable areas. In the lower part of this series stray sands occur which contain large quantities of gas. Practically all the gas from the *Clare*, *Broomfield*, *Mecosta*, and *Elba* pools is derived from this horizon. The middle

or Osage division of the Mississippian contains the Marshall or Napoleon sandstones from which the chemical materials of the Dow Chemical Company at Mt. Pleasant are secured. These brines occur low down on the flanks of a deep syncline. Higher on structure the sandstones produce gas.

The lower division of the Mississippian system consists mostly of shale, much of it black in colour. Near the base lies the Berea sandstone which has produced considerable quantities of oil in the *Saginaw* pool.

The Devonian rocks are the most important in the basin. They consist of dark to black shales at the top, limestones in the middle, and dolomites at the base. The calcareous rocks have proved to be the most valuable from the standpoint of oil production. Among them the *Dundee* ranks first as a source of oil. It produces in the *Denver*, *Mt. Pleasant*, *Yost*, *Porter*, and *Leaton* pools. A small amount of the oil in the *Ogemaw* (West Branch) and other pools seems to come from the Dundee. The oil may appear in one, two, or three porous zones near the top of the formation. The porosity may involve only a few inches or may range to more than 20 ft. Cores and fragments blown from wells indicate by their honeycombed condition that solution has produced the porosity.

The *Traverse* formation consists of limestones and shales. The former are often found to be porous and in a number of places contain commercial quantities of oil. This is especially the case in the Muskegon field where two different zones are oil bearing. Much of the oil in the *Ogemaw* and *Oceana* pools comes from the Traverse.

The unconformity below the Dundee which is so prominent in south-eastern Michigan has evidently produced a zone of cavities on the structure of central Michigan, for some oil (and some gas as well) has been found at this level. For instance, in the *Vernon* pool indications seem to point to the absence of the Dundee over much of the structure, so that the Detroit River or '*Monroe*' dolomites appear directly under the lower Traverse shales. In the *Muskegon* pool most of the gas comes from this horizon.

Cause of Oil Accumulation.

Exploration for oil began in 1865 near the town of Port Huron in south-eastern Michigan. Because of the small size of the wells further efforts were delayed until 1913, when some small wells were drilled near Saginaw. This led to further desultory prospecting in other parts of the State, but it was not until 1925 that a real interest was aroused in the possibilities of Michigan. In that year a fairly good well at Saginaw started an active drilling campaign. As a result the *Muskegon* pool was discovered in 1927 and the *Greendale* pool (Mt. Pleasant) one year later. Since then the valuable reserves in the central part of the State have been found to be much larger than was suspected.

Because of the recency of active exploration, knowledge of underground conditions is still very limited. It is gradually becoming apparent, however, that unconformities and structural 'highs' furnish the clue to the oil accumulations. The unconformity at the top of the Detroit River (Monroe) dolomite has been described by Newcombe [5, 1934, p. 550]. He also states that the break between the Dundee involves the removal of 200 ft. of strata in short distances. A break at the Berea horizon is indicated by its general absence in western Michigan and the presence of red clay and calcareous material at this stratigraphic level. Abundant evidence is also at hand from well-cuttings of a break between the Marshall and the Michigan series. Finally, the unconformity between the Parma sandstone and underlying formations is very striking and very widespread. The very interesting maps published by Newcombe reveal the fact that the oil has favoured the structurally

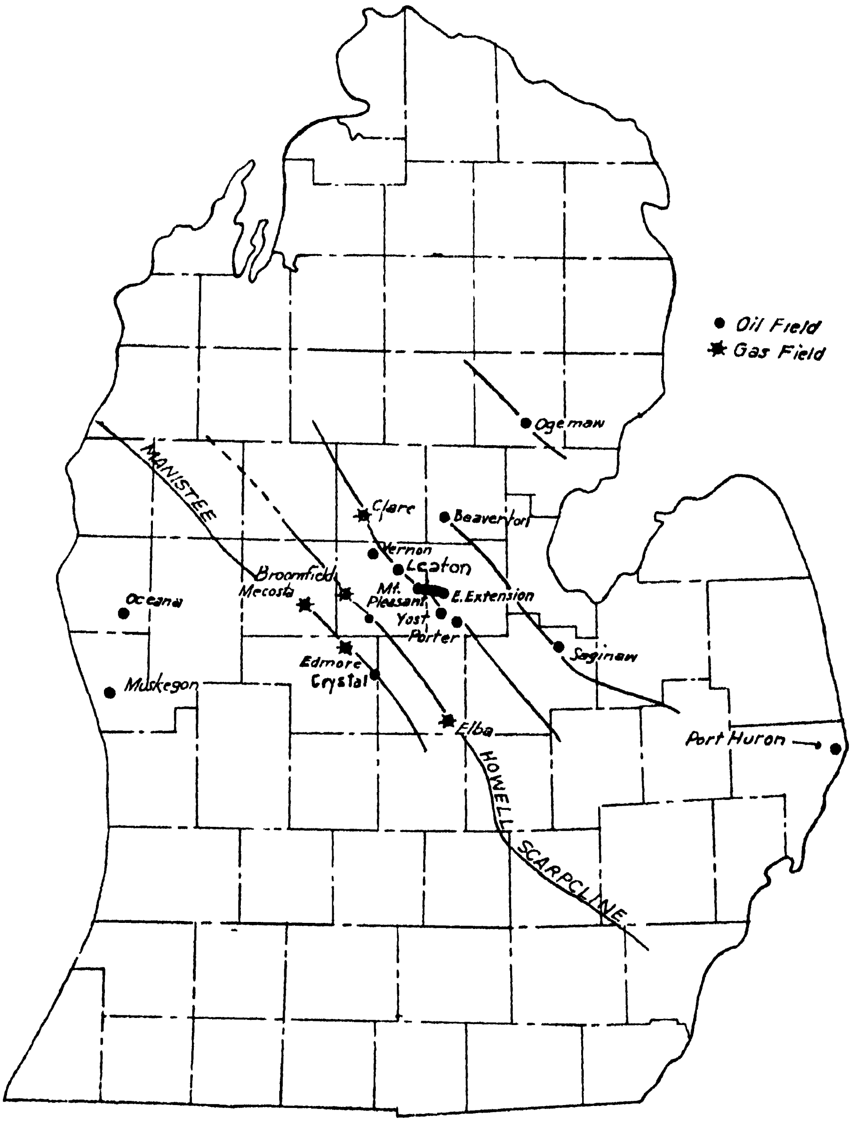

FIG. 3. Michigan Basin Province.

high places. The most prolific pools discovered up to date are located on the Greendale anticlinal trend described on page 74.

The general correspondence of structures in the Marshall Traverse, Dundee, and Monroe horizons indicates that uplift was repeated along the same lines and spasmodically. Whenever the uplift was great enough to lift the calcareous rocks out of the water an opportunity was presented for ground water to produce the necessary porosity. Thus the two essentials in providing a favourable environment for oil-forming materials were produced over wide areas in the Michigan basin.

Production.

Since 1925, when the yearly output amounted to only 4,000 barrels, the total has rapidly risen to over 15 million barrels in 1935. Considering the peculiarities of oil occurrence and the wide area over which the present pools are spread, it is not unreasonable to estimate that less than 10% of the ultimately productive territory has been found. Assuming that the total prospective area is over 10,000 square miles and allowing for a per acre production of 2,000 barrels on 2% of that area, the probable reserves exceed 250 million barrels.

V. Eastern Interior Coal Basin Province

The Eastern Interior Coal Basin province includes western and southern Indiana, north-western Kentucky, and practically all of Illinois. It is a natural geologic unit, being bounded on the east and north-east by the Kankakee branch of the Cincinnati Arch and on the south-west by the Ozark. The deepest part of the basin practically coincides with the point where the three States intersect. (See Fig. 4.)

Depositional History.

The history of sedimentation in this basin closely parallels that of the other large basins in the eastern part of the United States. After the Upper Cambrian and Lower Ordovician dolomites and sandstones were laid down, earth movements of considerable magnitude took place. The new sequence introduced by the St. Peter sandstone was probably not interrupted until the close of Silurian time. During the ensuing period of erosion some oil was formed on small domes in western Illinois (McDonough County, &c.) where the Hoing sand produces oil.

An angular unconformity at the base of the Upper Devonian (or Mississippian?) New Albany (Chattanooga) shale reveals the second period of deformation. Erosion and truncation of beds beneath the unconformity was probably widespread, but insufficient data make further elaboration impossible. Nevertheless, it is logical to assume that the small production found in the so-called 'Corniferous' limestone is genetically related to it. Such production has been found in Clark County, Illinois, and at Terre Haute, Indiana. The overlying Mississippian sediments are very thick and include the most valuable oil horizons in the province.

The *Kinderhook* at the base is made up of shales, limestones, and thin sandstones, one of which produced oil in a well drilled in Martinville township of Clark County. The overlying Osage division includes the *New Providence* shale, near the base of which some oil has been found in Kentucky (Ohio and Grayson Counties). The *Meramec* limestones (Ste Geneviève, St. Louis, Spergen, and Warsaw) contain porous zones in which important quantities of oil and gas have accumulated. In Illinois the producing horizon is called the *McClosky* 'sand', in Indiana it is referred to as the *Ste Geneviève* limestone, and in Kentucky only the *Warsaw* limestone is productive. The oil and gas in these limestones are probably related to the unconformity which appears in the section between them and the Chester division.

The Chester division is made up of an alternation of thin limestones and sandstones, each of which has received a name. By far the largest part of the production of the province is derived from the sandstones. In Illinois they are called by various names such as *Lindley*, *Benoist*, *Stein*, *Biehl*, *Carlyle*, *Tracey*, and *Kirkwood*. The last two have been traced over the widest area and therefore take on the greatest importance, although it is very probable that they are not continuous sandstones. In Indiana the important

Stratigraphy and Producing Horizons in Eastern Interior Province

		Illinois		*Indiana*		*Kentucky*	
System	*Formation*	*Thickness*	*Sands*	*Thickness*	*Sands*	*Thickness*	*Sands*
Pennsylvanian .	McLeansboro	1,000	Casey	500	..	..	..
	Carbondale	375	Shallow sands	350	..	..	..
	Pottsville	500	Bridgeport	300	Mansfield	350	Stray
			Robinson	..	..	..	Niagara
			Buchanan	..	..	..	Channel
Mississippian .	Chester	800	Kirkwood	800	Cypress	850	Stephens
			Tracey, &c.	..	Mooretown	..	Jett, Jackson
					Paoli, &c.	..	Barlow
	Meramec	400	McClosky	700	Ste Geneviève	450	Warsaw
	Osage	400	..	400	..	400	Major
	Kinderhook	60	Carper	..	..	..	..
Devonian . .	Upper	150	..	100	..	200	Rockhaven
	Onondaga	150	Corniferous	200	Corniferous	50	..
	Lower	350	..	20	..	..	..
Silurian . .	Niagara	10	Hoing	250	..	170	..
	Lower	100	..	20	..	..	..
Ordovician . .	Cincinnati	100	..	400	..	700	..
	Trenton, &c.	500	Trenton	600	..	..	..
	St. Peter	100	..	20	..	..	..
	Canadian	500	..	450	..	..	..

producing sandstones are the *Cypress*, *Elwren*, *Brandy Run*, and *Mooretown*. Some of the Chester limestones also produce oil and gas. Outstanding among them is the *Paoli* limestone at the base of the division. In Kentucky the producing sandstones in descending order are the *Stephens*, *Jett*, *Jackson*, and *Barlow* sands.

Following uplift and deformation at the close of Chester time much of the series was removed from the structurally high places. The materials were reworked in Pottsville time, with the result that the Lower Pennsylvanian strata are very lenticular. Some of them have large accumulations of oil and gas, especially in south-eastern Illinois. The *Bridgeport*, *Robinson*, and *Buchanan* sands, for instance, have accounted for a considerable portion of the oil recovered to date. In Indiana one of the important sands in the Pottsville is the *Mansfield* sand. The '*Channel*' sand in Kentucky is interesting because it occupies an old river channel cut out of Chester rocks in early Pottsville time.

Structural Control.

The intimate association of the pools of these States with the *La Salle anticline*, the *Rough Creek fault* zone, and certain smaller 'structures' proves that they are genetically related. The La Salle anticline, at the southern end of which the most prolific pools were found, had its inception early in the Palaeozoic era. It is probable that the Trenton production of Clark County and the Waterloo pool (south-western Illinois) was formed as a result of deformation in Late Ordovician time. Much more definite evidence of deformation appears between Meramec and Chester time. Renewed uplift with the formation of porous zones in the Middle Mississippian limestones created ideal conditions for the trapping of oil and gas. This was the first pulsation of the Appalachian revolution. More followed during Chester time, with the result that numerous sandstones in the sequence are oil saturated. Many pools of small extent

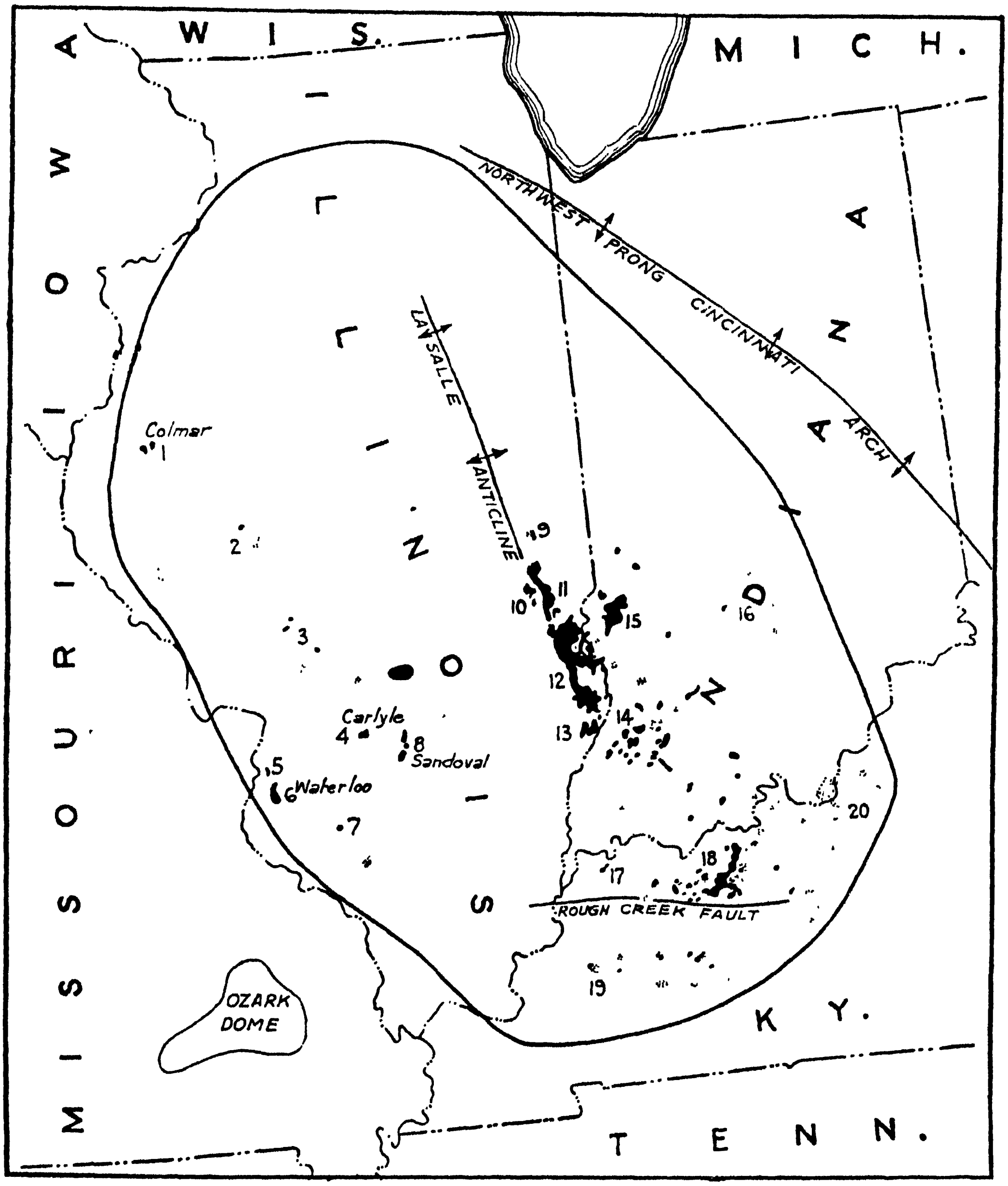

FIG. 4. Oil- and gasfields of Eastern Interior Province.

have different oil and water contact levels in approximately the same sands, which proves that there was no intercommunication or migration. The oil must have formed in place at the time of uplift. Much oil was undoubtedly lost during the long erosion interval between Chester and Pottsville time. But when renewed deposition took place spasmodic uplift brought portions of the anticline into the zone of optimum conditions for oil formation so that successively higher zones in the Pennsylvanian were saturated.

The oilfields in Kentucky are located mostly on the north side of the Rough Creek fault zone, but the reason for this is still more or less of a puzzle. Russell [2, 1932, p. 246]

50% exhausted. Probable reserves, therefore, can be estimated at 15 million barrels. Taking the province as a whole, the most that it can be expected to contribute in the future (with present exploitation methods) is 100 million barrels, even allowing for additional pools in south-western Illinois and south-eastern Kentucky.

VI. Western Interior Coal Basin Province

The Western Interior Coal Basin covers parts of Iowa, Nebraska, Kansas, Missouri, and Oklahoma. Geologically, it is limited by outcrop belts of Early Palaeozoic rocks such as those of the Ozark Dome in Missouri and of the Arbuckle

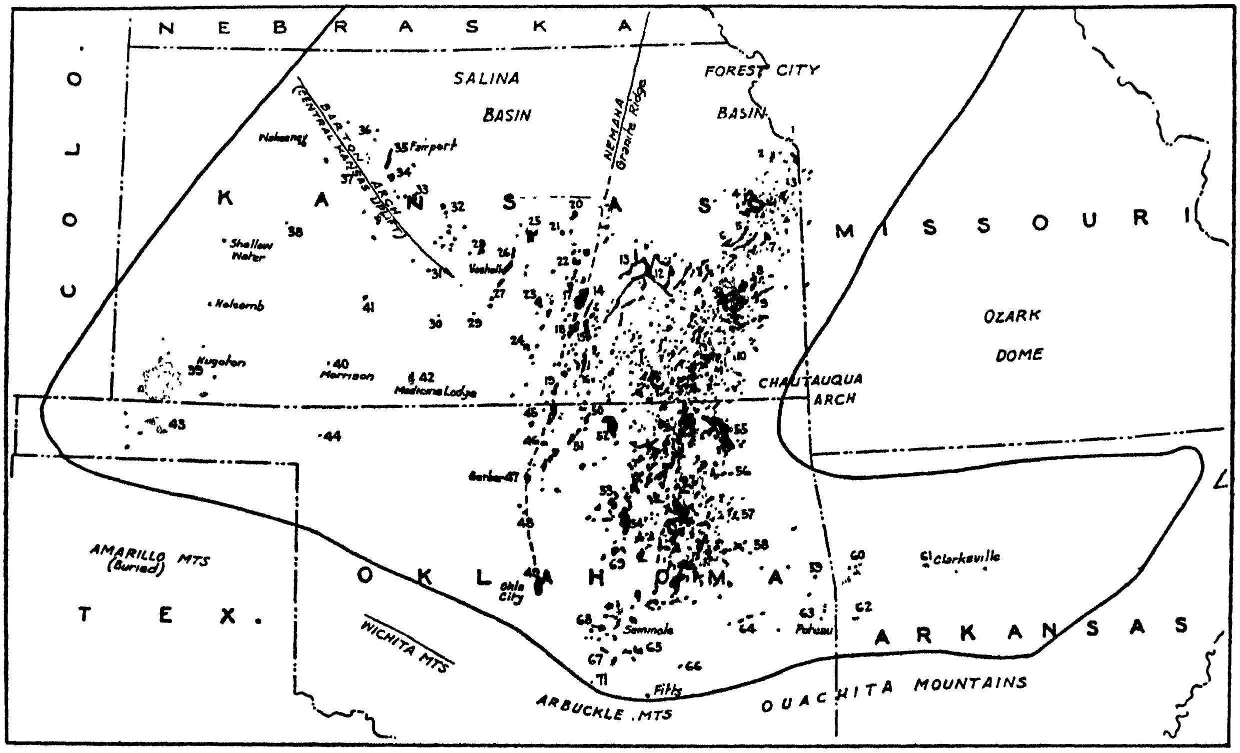

FIG. 5. Western Interior Province.

states that the strata north of the fault zone are somewhat folded and that some of the pools are associated with anticlines. In the eastern part of the productive belt there is little or no folding. Many pools show no relation to structure whatever. The information at hand with regard to the pools in south-eastern Indiana is also meagre. Those discovered in recent years and for which drilling records were well kept seem to be located on structural 'highs'.

Production Data.

The amount of oil produced in this province up to the end of 1935 totals approximately 465 million barrels. Illinois should be credited with 421 million barrels of this. Since the productive acreage in south-eastern Illinois is about 92,000 acres, Bell [5, 1934, p. 565] estimates the per acre production to be 4,400 barrels. The future production still in reserve may be placed at nearly 50 million barrels. South-western Indiana has produced about 20 million barrels to date, which indicates a per acre production of less than 800 barrels. It is believed that the area is 80% exhausted, so that the reserves probably do not exceed 4 million barrels. North-western Kentucky has accounted for about 24 million barrels and is scarcely more than

and Wichita Mountains in southern Oklahoma. Within the area there are similar prominent tectonic elements concealed under a cover of Pennsylvanian strata. The best known is the *Nemaha Granite Ridge* which is a very narrow belt of deformed rocks trending nearly north and south through eastern Nebraska, Kansas, and Oklahoma. Another is the *Central Kansas Uplift* which trends south-easterly from north-western Kansas into south-western Missouri (sometimes called the *Barton* and *Chautauqua* arches). These two are genetically related to the richest oil- and gas-pools in the province. (See Fig. 5.)

Stratigraphy.

The stratigraphical sequence is shown in the table on page 79. Tertiary rocks cover the area in the western part, but have no economic interest. They are underlain by a considerable thickness of Cretaceous rocks which also have no economic value. The Permian system is represented by two distinct types of materials, an evaporite series at the top with much red and green shale and a marine sequence below. The latter bears a striking resemblance to the Pennsylvanian sequence, for it consists of alternating layers of limestones and shales. Occasional sandstones or sandy

phases in the shales have enough porosity to become reservoirs for oil. Sometimes the limestones have original or secondary porosity characters which allow them to serve in that capacity.

Stratigraphy and Producing Sands—Western Interior Province

		Kansas		Oklahoma	
System	*Formation*	*Thickness*	*Sands*	*Thickness*	*Sands*
Tertiary	..	300	..	..	..
Cretaceous	..	500	..	..	..
Permian	Red Beds	500	..	800	..
	Big Blue	600	Hugoton gas	600	Hoy and Kisner
Pennsylvanian	Wabaunsee	500	Tarkio, &c.	700	Hotson
	Shawnee	500	Elgin, Topeka	600	Topeka
	Douglas	100	Boyer and Stalnaker	300	Endicott
	Lansing	300	Oswald	500	Stalnaker
	Kansas City	300	Layton, Encill	600	Layton, &c.
	Marmaton	400	Peru, Oswego, &c	700	Peru, Oswego, Calvin
	Cherokee	500	Bartlesville, &c.	1,000	Skinner, Red Fork
			Burgess	..	Burbank, Glenn,
			Basal congl.		Bartlesv.
				..	Tucker
Mississippian	Chester		Vaniman		Cromwell,
		500		300	Dutcher
	Boone	350	Chat, Welch	350	Mississippi Lime
			Misener		Misener
	Chattanooga	100		100	
Sil.-Devon.			Hunton		Hunton
Ordovician	Hunton	50	.	50	..
	Sylvan	100	Viola, Leon	100	Viola
	Viola	100	Wilcox	100	Wilcox,
	Simpson	50		200	Hominy, Burgen
	Arbuckle	100	Siliceous Lime	300	Turkey Mt., Arbuckle
Cambrian	Reagan	30	Basal sand	..	..

The highest producing horizon, for instance, seems to be a porous limestone in the Big Blue series and it is usually referred to as the Hugoton gas sand. The *Hugoton* gasfield is located in south-western Kansas and appears to be one of the large gas areas of the country. In Oklahoma the *Hoy* and *Kisner* sands produce some oil and gas in the north-central part of the State. The list of petroliferous zones in the Pennsylvanian system is quite impressive and the reader will find the names of the more important ones in the table on this page. The most prolific sands lie close to the base of the system in the Cherokee division, and among them the *Bartlesville*, *Burbank*, and *Glenn* sands stand out because of large production east of the Nemaha Granite Ridge. They are extensive sheet sands in which the oil and gas deposits are trapped by lack of permeability in the up-dip areas.

The Mississippian system contains limestones and shales in the upper part (Chester), thick limestones in the middle (Boone), and black shales at the base. The Chester division produces oil in Scott County, Kansas (*Vaniman*), and in south central Oklahoma where the *Cromwell* and the *Dutcher* sands have accounted for important amounts of petroleum. The Boone is usually the uppermost portion of the system, because of the extensive unconformity between it and the Pennsylvanian. On structural 'highs' much chert and other insoluble material have collected which seem to furnish an ideal gas reservoir and have also trapped much oil in central Kansas. This is commonly called the '*chat*' horizon or the *Welch* chert. At the base of the system is another prominent unconformity which is often marked by the local occurrence of sandstones. Oil at this level is referred to the *Misener* sand.

In the basins between the positive structural features older rocks appear. In some basins the Silurian and Devonian limestones, usually called collectively the *Hunton* formation, are quite thick. Where their eroded and truncated edges appear beneath the unconformably overlying strata some oil has been trapped. It has been found quite productive in central Kansas and also in south central Oklahoma. The older Ordovician rocks also appear in narrow bands beneath the unconformity. The Sylvan at the top is mostly shale, the *Viola* largely limestone and dolomite, the Simpson mostly green shale and sandstone. The *Arbuckle* formation was named from the mountains in southern Oklahoma where it is 8,000 ft. thick. Farther north it thins abruptly and on structures it is quite thin or even entirely absent. Each of these Ordovician formations that has either initial porosity (Simpson sandstones) or secondary porosity (limestones and dolomites) may be oil bearing. Indeed, in recent years by far the largest part of the production has come from strata of this age. The various sands in the *Simpson* lead in Oklahoma where they have considerable thickness. In Kansas, on the other hand, the *Arbuckle* (*Siliceous Lime*) is the most prolific horizon at the present time.

Relation of Structure to Accumulation.

The producing horizons in this province may be divided into two classes according to their relation to unconformities. The pre-Pennsylvanian horizons show unmistakable relationship to unconformities. The most striking of these is the post-Mississippian unconformity, for deformation was profound along narrow lines. The best fields such as the *El Dorado* in Kansas and the *Oklahoma City* field in Oklahoma are associated with the buried Nemaha Granite Ridge. Faulting brought up the older Palaeozoic rocks along narrow and straight *en échelon* belts. Subsequent solution of the calcareous strata produced the necessary porosity, and their relatively high position with reference to surrounding basins provided optimum conditions for oil formation. Some pools which lie in a parallel trend, such as the famous *Cushing* pool in eastern Oklahoma (east of the Granite Ridge) and the *Voshell-Burrton* trend in central Kansas (west of the Ridge), were formed at the same time and in the same manner.

The post-Devonian unconformity is best illustrated in the *Central Kansas Uplift* which extends from the north-western part of Kansas south-easterly towards the south-eastern part of the State where it merges with the Ozark Dome. It is a broad, turtle-back type of fold from which every formation except the Arbuckle is missing over large areas. Oil- and gas-pools dot this plateau wherever local 'highs' or narrow cross trends intersect it. On the periphery where the truncated bands of older rocks appear beneath the Pennsylvanian, oilfields are being found at the present time.

The producing horizons in the Pennsylvanian and Permian do not reveal such striking relation to unconformities. Nevertheless, it is believed that they also owe their productivity to similar environments. Deformation and uplift along the older zones continued during Pennsylvanian time in spasmodic fashion. This is abundantly

proved by the familiar 'thinning of the section' above older 'structures'. (See especially McCoy [5, 1934, p. 581]). Therefore it is not uncommon for wells to have numerous 'shows' and shallow gas sands in the higher formations when located on prominent buried structures. This was the case notably at El Dorado, Kansas, and Garber, Oklahoma.

As a general rule these upper sands become more valuable with depth. At present the highest one of great production is the porous zone at the top of the Lansing (or Kansas City) limestone sequence. In western Kansas this is called the *Oswald* horizon and in northern Oklahoma the *Stalnaker* sand. In the Russell pool of western Kansas where the Oswald was named there are at least eight distinct porous levels in the limestone which have produced oil. They lie at various levels below the top down to 285 ft. It is interesting to note that in one well this lowest level lies immediately above the pre-Cambrian granite.

Still lower are the sands in the Marmaton and in the Cherokee. These sands produce almost exclusively from areas lying east of the Nemaha Granite Ridge. In general the oil and gas are trapped by the up-dip termination of their permeability. Sometimes this is due to the thinning of the sandstone, sometimes to the complete thinning out of the sandstone, and in a few cases to the presence of cementing materials. Somewhat peculiar conditions are exemplified by the so-called '*shoestring sands*' which extend for many miles through Butler and Greenwood Counties, Kansas. They are now believed to be off-shore bars or barriers formed in the Cherokee seas. It should also be added that many small pools in eastern Oklahoma produce from these sands on local domes and anticlines.

Production Data.

At the close of 1935 the production figures for Kansas stood at 779 million barrels and for northern Oklahoma at 3,500 million barrels. Of the total for Kansas 688 million should be credited to the eastern part of the State (east of the prime meridian), and if this is equally distributed over the 566 square miles of productive territory, it gives a per acre figure of 2,000 barrels. A reasonable estimate of the reserves in eastern Kansas is 200 million and for western Kansas 800 million barrels. A similar estimate for Oklahoma is 1,500 million barrels. It is interesting to note that each State has had certain rich spots or bonanzas. For Kansas these spots are Rainbow Bend (10,000 bbl. per acre), Churchill (20,000 bbl. per acre), Oxford (20,000 bbl. per acre), Valley Center (15,000 bbl. per acre), Voshell, Houry, Burrton, and El Dorado (7,000 bbl. per acre). For Oklahoma the two mort important field are Oklahoma City (estimated ultimate 75,000 bbl. per acre) and Seminole (estimated ultimate 40,000 bbl. per acre). Other rich spots are Burbank, Cushing, Garber, Glenn, and Tonkawa.

VII. The Wichita Amarillo Mountain Province

The oil- and gasfields in southern Oklahoma, north central Texas, and the Panhandle of Texas have distinctive characteristics which entitle them to separate treatment. The reason for this is the fact that they are associated with pronounced structural features due to Hercynian (Appalachian) mountain building movements. These are well displayed in the Arbuckle Mountains and Criner Hills of southern Oklahoma and the Wichita Mountains of southwestern Oklahoma. They have also been revealed by drilling in the Amarillo district of Texas and the Red River Uplift district of northern Texas. Some of the pools are superposed on the buried mountains, others on their flanks and some on small parallel zones of deformed rocks. (See Fig. 6.)

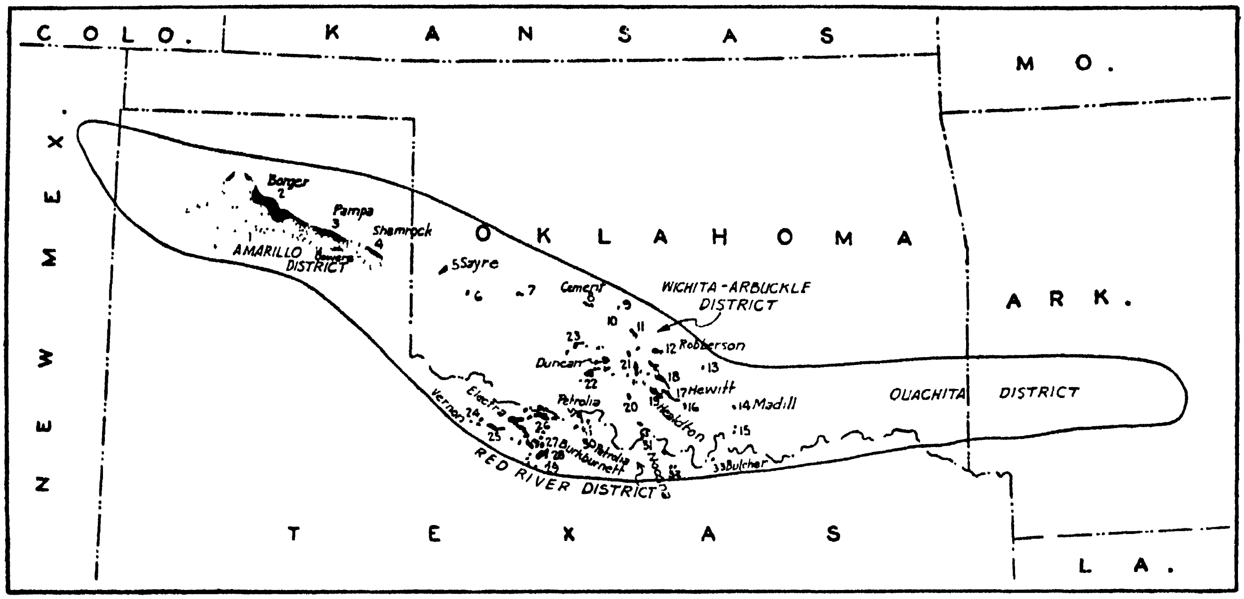

FIG. 6. Ouachita–Amarillo Province.

Stratigraphy

The stratigraphy of this province is very interesting and also very difficult because of variations in lithology from east to west. The surface rocks in the western part of the area are Tertiary and Mesozoic sediments which have no economic interest. They rest unconformably upon Permian strata which crop out in successively older bands towards the east. No production has been found in the Double Mountain or Clear Fork groups, but the Lower Permian rocks called *Wichita-Albany* contain large quantities of gas and some oil. In Oklahoma production has been obtained from pools in Beckham, Caddo, Grady, Stephens, and Garvin Counties. In northern Texas small production has

been found in pools located in Wichita, Clay, and Archer Counties. In these States the Wichita-Albany consists of shales and sandstones which have prominent red-coloured zones in the east and grade into calcareous rocks towards the west. For instance, in the *Sayre* pool of Beckham County and in the large *Panhandle* district the producing horizon is dolomite (top of *Big Lime*). It is about 250 ft. thick and contains porous zones throughout, making it the most widespread gas horizon in the Panhandle district. Oil occurs in the same dolomite farther down the dip.

The so-called '*Gray Lime*' of the Panhandle district is believed to be of Pennsylvanian age. It has furnished the largest gas-wells and has accounted for some of the oil as well. Farther east the Upper Pennsylvanian rocks are called the *Pontotoc* formation and consist of very coarse clastics. It is not improbable that the '*granite wash*' of the Panhandle district is the correlative of the Pontotoc, for it consists of similar detrital materials. Much gas and considerable oil have been recovered from it.

the pre-Cambrian igneous rocks, and there some gas has been found in the crevices of the weathered surface of the granite.

Relation of Accumulation to Structure.

It appears from the above that practically all the oil and gas in this province originated during Pennsylvanian and Early Permian time. The oldest producing horizons are directly associated with the unconformity at the base of the Pennsylvanian. The relationship is emphasized by the fact that the granite produces gas in Texas, showing that only the necessary porosity was needed to trap the gas formed during the break in sedimentation. The rest of the gas and the oil in the Texas Panhandle is associated with the other unconformity which is post-Glenn and pre-Pontotoc, for, although much of it lies at stratigraphically higher levels, the available evidence indicates that migration within and about the periphery of the large structure at that point has been rather free and easy.

Stratigraphy and Producing Horizons—Wichita–Amarillo Province

		Oklahoma		*North Texas*		*Panhandle*	
System	*Formation*	*Thickness*	*Sands*	*Thickness*	*Sands*	*Thickness*	*Sands*
Permian	Double Mountain	..	..	..	..	..	..
	Clear Fork	200	..	200	..	..	..
	Wichita	900	Shallow 'pays'	900	Shallow 'pays'	250	Big Lime
Pennsylvanian	Pontotoc	500	Sands	200	?	..	..
	Cisco or Glenn	1,000	8 'pays'	1,400	6 'pays'	300	Gray Lime Granite Wash
Ordovician	Viola	50	Viola	..	..	..	..
	Simpson	100	Simpson	..	..	..	..
	Arbuckle	400	Arbuckle	500	Ellenburger	..	..
Cambrian	Reagan	..	..	..	..	..	..
Pre-Cambrian	Granite, &c.	..	..	..	..	..	Some gas

The base of the Pontotoc is marked by a widespread unconformity. In the basins between the mountain uplifts of this province an enormous thickness of older Pennsylvanian shales and sandstones (Glenn, &c.) was laid down. Many of the porous strata yield large quantities of oil where they appear on the flanks of structures. In Stephens County, Oklahoma, for instance, eight different sands are productive in the *Empire* pool and the *West Duncan* pool. Indeed, by far the largest portion of the oil has been derived from sands in the Glenn formation. This is true in northern Texas as well as in southern Oklahoma. Important pools in Oklahoma producing from these horizons are the *Healdton Graham*, *Hewitt*, and *Crinerville* pools in Carter County.

Below the Glenn formation and its correlatives there is another unconformity which is both widespread and marked by great deformation in the older rocks. It is common, therefore, to find the Mississippian, Devonian, Silurian, and Upper Ordovician strata absent in this area and always on the prominent structures. Some oil has been found on the truncated tops of these older rocks. For instance, in the *Robberson* pool of Garvin County the Viola limestone and the Simpson sandstones produce some oil. In the Franksgraben the Viola and Simpson produce oil. At Crinerville the Arbuckle limestone has accounted for some of the oil. Recently production has been found in the Arbuckle (Ellenburger) in the north Texas district. In the Panhandle district the Pennsylvanian rocks rest directly on

Structural Control.

In addition to the evident importance of unconformities the influence of structure should be emphasized. From all published information at hand it now appears probable that this province is underlain by a vast series of block-faulted uplifts. They are arranged in *en échelon* groups. Some are high and some are low, but all seem to have the steepest side to the north or west. On the basis of van der Gracht's monumental studies [2, 1931, p. 991] these fault blocks were produced during the 'Wichita phase' of orogeny which came early in the Pennsylvanian period and which corresponds to the unconformity at the base of the Glenn formation. The Wichita phase extended over a period of geologic time which includes the Upper Mississippian and the oldest Pennsylvanian. Its effects may be noted as far north-east as the Criner Hills, but not in the Arbuckle Mountains or the Ardmore Basin which lies between them. The latter tectonic elements were produced by the Arbuckle phase of orogeny which came in Late Pennsylvanian time and corresponds to the unconformity between the Pontotoc and older strata. No doubt some rejuvenation of the more southerly structures took place at this time, for unconformities are found in the sequence.

In addition to the buried mountain ranges mentioned in previous pages, the Wichita group includes the *Red River Uplift* which has been traced from eastern Cooke County, Texas, to central Foard County and the Landreth–Sigler

line of disturbance on its southern flank. Between the Criner Hills and the Wichita Mountains the Hewitt, Healdton, Woolsey, Loco, and other short ridges have been discovered by deep drilling. Each of these is directly and intimately associated with important oil accumulations. Indeed, the subsurface correspondence between anticlines and oil occurrence is as striking as it is in the Rocky Mountain province. Steep dips are the rule here in distinction from the fields of the Western Interior province. This has facilitated short-distance migration within the structure. In this connexion it should be emphasized that the patchy, disconnected porosity in many Pennsylvanian sands of this province has produced quite a number of anomalous oil accumulations. They are especially common in the north Texas district.

Production Statistics.

Up to the end of the year 1935 the Panhandle district of this province has produced 257 million barrels of oil as well as a very large amount of gas (over 4 billion thousand cu. ft.). The gas-productive area is nearly 1 million acres, and competent engineers estimate that its future production will be 10 billion thousand cu. ft. Oil production extends over approximately 100,000 acres and is expected to contain about 200 million barrels in reserve. To date this production has been only on the north side of the structure. Several small wells drilled within the last year indicate that some additional reserves may be stored on the south side of the Amarillo Mountain area.

Ultimately there will probably be a zone of pools eastward through south-western Oklahoma (where oil was recently discovered near Altus) which will connect with the pools in northern Texas. The total production from the latter amounts to 490 million barrels. Considering the peculiarities of oil occurrence in the Red River Uplift district it may confidently be predicted that at least 200 million barrels are still stored underground. Data on the southern Oklahoma district of this province were furnished by C. W. Tomlinson who states that the production to the end of 1935 was 420 million barrels and that estimates of reserves amounted to 100 million barrels.

VIII. The Bend Arch Petroliferous Province

Somewhat closely associated with the fields of the Red River Uplift are the fields of north central Texas. They extend southward through Archer, Young, Stephens, Eastland, and Brown Counties and include a few scattered pools in the adjacent counties. Geologically they are related to an arch prominently developed in the earliest strata of Pennsylvanian age, the Bend Arch. To the east of this arch lies the Strawn Basin, in which were laid down great thicknesses of coarse clastics as a 'molasse' from the land mass of Llanoria. The north-western side of this land mass was rising rapidly at the time of the Wichita phase of orogeny described in the preceding section. Therefore the Strawn sediments thicken very markedly towards the east up to the 'boundary fault' of the ancient land area. In Upper Pennsylvanian time the whole region was tilted towards the west. Inasmuch as the lowest Pennsylvanian strata (Bend series) had been subsiding towards the east with the formation of the Strawn wedge of sediments, this tilting movement produced a broad arch at that level.

Stratigraphy.

The stratigraphical sequence as revealed by deep drilling on the arch is shown in tabular form below. Since the arch is highest at the south end and pitches gently towards the north the oldest rocks crop out south of the big bend in the Colorado River in the eastern part of San Saba County. This area is often referred to as the Llano-

Stratigraphy and Producing Horizons—Bend Arch Province

System	*Formation*	*Thickness*	*Sands*
Permian	Wichita	200 (north) only)	..
Pennsylvanian	Cisco	2,000	Many lenticular sands
	Canyon	1,000	..
	Strawn	2,000	Many sand lenses
	(Unconformity)		
	Smithwick	600	Caddo or Breckinridge
	Marble Falls	500	Ranger or 2nd 'pay'
	(Angular unconformity)		
Mississippian	Barnett	0–150	..
	(Unconformity)		
Ordovician	Ellenburger	1,000	..

Burnet Uplift or the Central Mineral Region of Texas. Pre-Cambrian, Cambrian, and Ordovician rocks are exposed there as well as the black shale of Mississippian age (Barnett) which rests unconformably upon their eroded edges. The Bendian strata of earliest Pennsylvanian age rest upon the Barnett shales with unconformable relations. They are divided into two formations, the lower (*Marble Falls*) consisting of dark-coloured limestones and the upper (*Smithwick*) consisting of black shales and interbedded limestone. These two formations have furnished the largest proportion of the oil and gas of this province. Porous zones are found at various levels in the Marble Falls limestone and also in the so-called Caddo Lime which appears about 200 ft. above the top of the Marble Falls. The upper 'pay' is the chief producing horizon in Stephens County, where it is from 40 to 50 ft. thick and variously called *Caddo Lime*, *Breckinridge Lime*, or *First Pay*. Near Ranger in Eastland County, where the most prolific production in the province was discovered, the *Second Pay* or *Ranger Lime* yields the oil.

The *Strawn*, which lies above the Smithwick unconformably, consists of shales, sandstones, and thin limestones. The sandstones are very patchy and vary greatly in thickness from place to place. However, they are porous and therefore serve as reservoir rocks in many small pools extending as far north as Stephens County. Local names have been used for these sands. The *Canyon* also consists of shales, sandstones, and limestones, but does not seem to contain any petroliferous sands. On account of the northward pitch of the arch the *Cisco* attains its full thickness only at the northern end of the province. There it is 2,000 ft. thick and contains strata similar in lithology to those of the Canyon formation. The sandstones, again, are very lenticular, but contain important accumulations of oil at various horizons in the formation. In southern Archer County, where this formation has been found most important, the better sands are in the lower half of the formation. They have received local names such as *Dalmar*, *Wilmot*, *Swastika*, *Gose*, and *Texhoma*. The porosity of the best sands averages about 22%, and the per acre production is estimated to be 7,000 barrels.

Conditions of Oil Accumulation.

The striking alinement of pools close to the highest portions of the arch indicates plainly that structural relief is

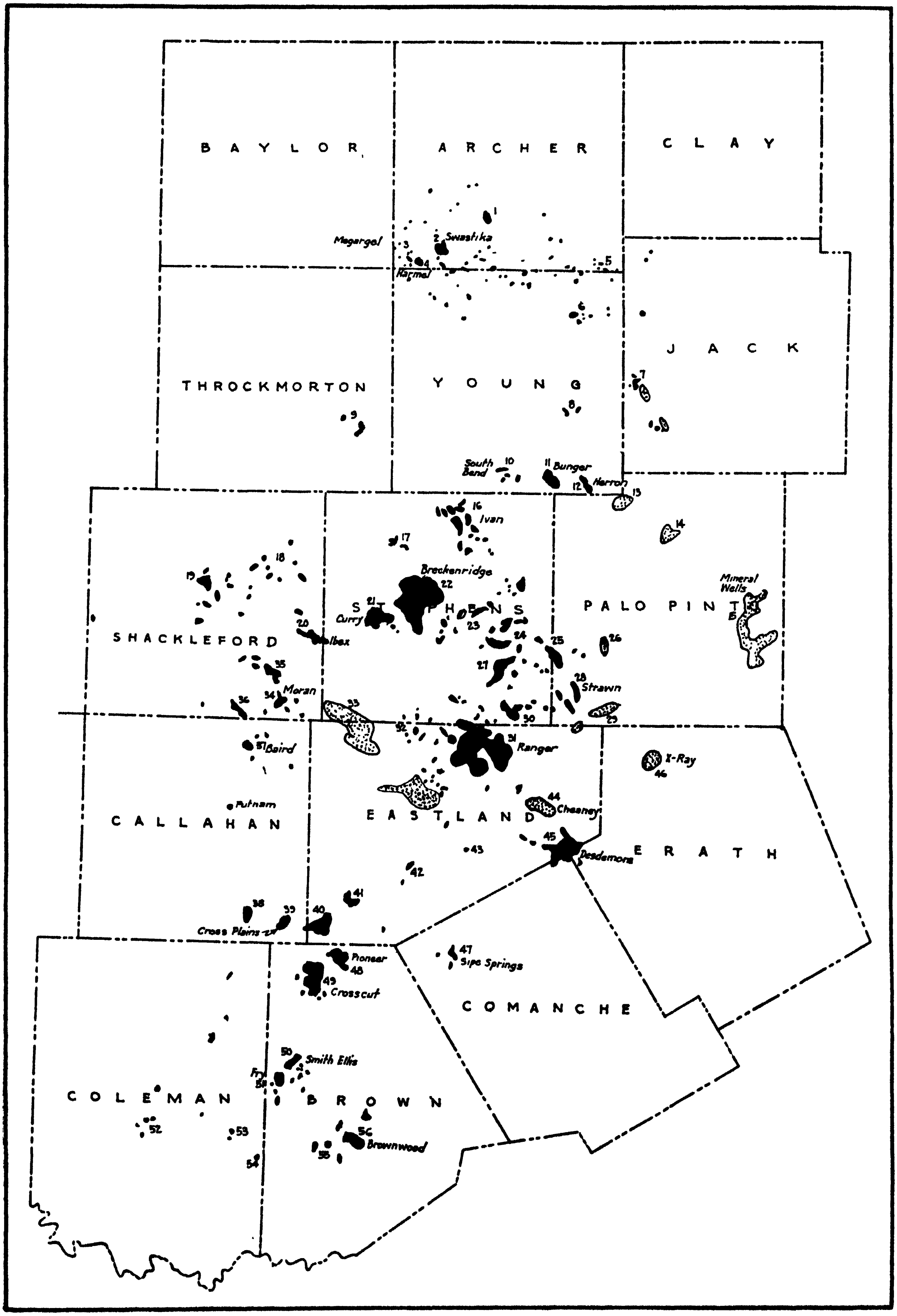

FIG. 7. Bend Arch Province.

important in this province. The relatively broad axis of the arch is modified by local domes, anticlines, noses, and other minor structures. Quite a number of them, like the Breckinridge dome and the Ivan dome in Stephens County, the Ranger and Eastland noses in Eastland County, and the Strawn dome in south-western Palo Pinto County, have large accumulations of oil upon them. In many pools, however, the structural relationship is not obvious. There the accumulations are controlled entirely by porosity conditions. Many cases are on record where the producing sand becomes thin or merges with shale beds at the boundary of the producing area. On the whole this has been the most difficult province to locate oil-pools in, and therefore has the doubtful honour of showing the largest percentage of dry holes.

Production.

The amount of oil produced from this province up to date exceeds 354 million barrels. Of this total more than one-third should be credited to Stephens County. Eastland and Shackelford Counties rank next in importance. It may be conservatively estimated that 70% of the productive area has been discovered. The per acre production over much of the province has been disappointingly low, although certain of the richer areas have reached close to 6,000 barrels per acre. The future reserves will therefore hardly exceed 125 million barrels.

IX. The Gulf Embayment Province

The Gulf Embayment involves eastern Texas, southern Arkansas, all of Louisiana, and a considerable portion of Mississippi. It is so called because the Tertiary and Cretaceous rocks which were laid down as ancient delta deposits by the Mississippi River reach into the United States as a large bay from the Gulf of Mexico. Because of the large area affected and the somewhat different conditions existing in its various parts it will be convenient to subdivide it into four districts. These have been named the *Balcones Fault district* (east central Texas), the *Sabine–Ouachita Uplifts district* (northern Louisiana, southern Arkansas, and north-east Texas), the *Reynosa Escarpment district* (south Texas), and the *Salt Dome district* (southern Texas and southern Louisiana). (Fig. 8.)

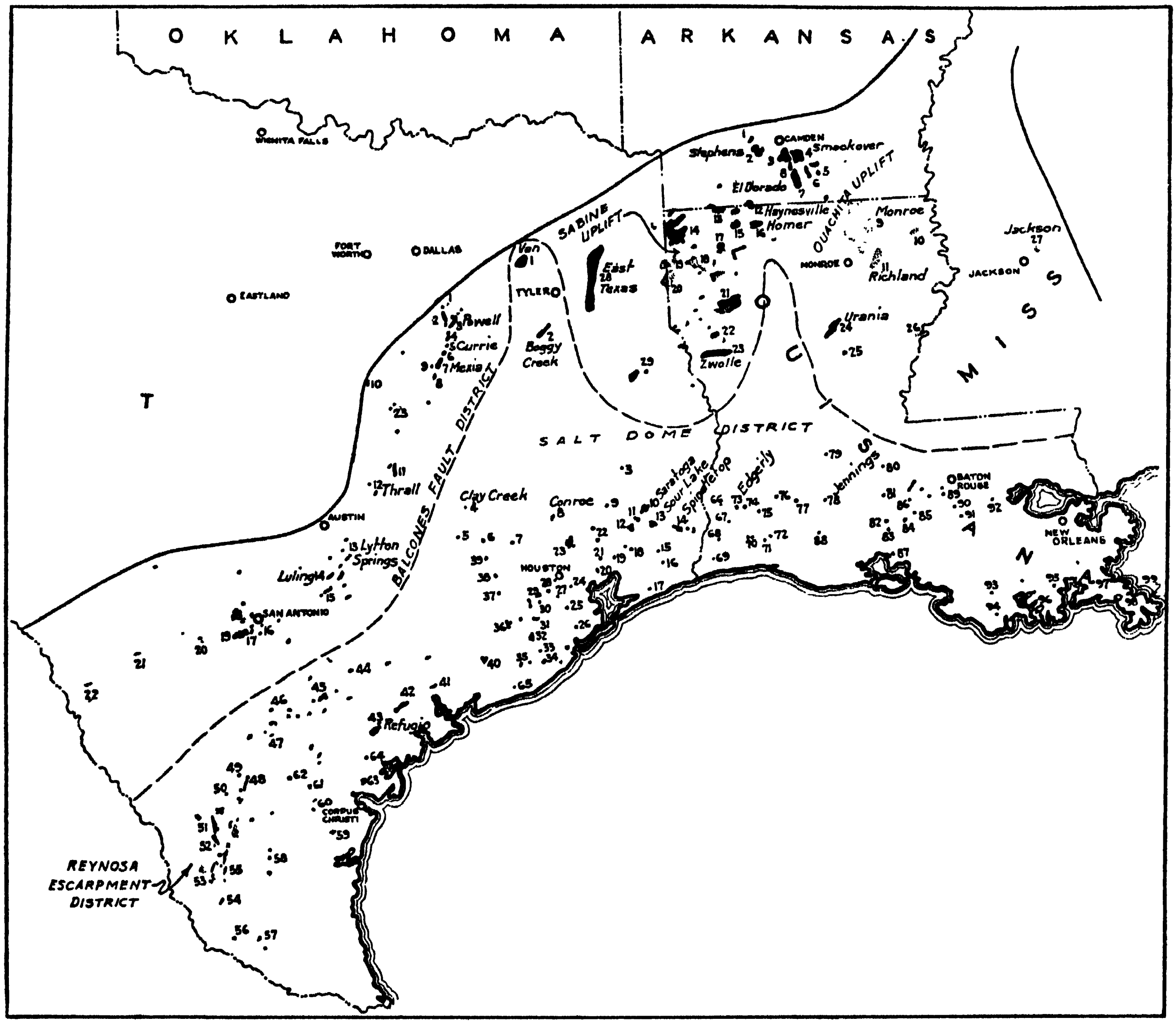

Fig. 8. Gulf Embayment Province.

Geological History.

The geological history of this area begins with the sinking of Llanoria, that ancient land in Louisiana which had

furnished sediments to Texas and Oklahoma during Palaeozoic time and which culminated its role as a positive element with one grand orogenic flourish in Pennsylvanian time. The tensional stresses which followed the Appalachian Revolution allowed Llanoria to sink and slip towards the Gulf. By Comanchean time it had become submerged by ocean waters and sank rapidly so as to accommodate 4,000 ft. of red shales, sandstones, limestones, and anhydrite. These materials have been reached and penetrated in a few wells in the northern part of the province. The fact that they are commonly found dipping more steeply than the Cretaceous rocks indicates that some deformation took place between the two periods.

been known for a long time. It extends through east central Texas from a point east of Dallas southward to a point west of San Antonio. It seems to coincide closely with the surface trace of the line marking the north-west boundary of the folded Palaeozoic rocks of the Ouachita facies. Another belt of short *en échelon* faults has been found in a closely parallel zone some distance east. It has been named the *Mexia fault zone* after one of the prominent oilfields discovered within it. In general, the area between the two zones is a belt of graben which has recently been traced into south-west Arkansas. The Mexia fault zone seems to coincide with the north-west boundary of the buried Llanoria. These two zones of faulting are

Stratigraphy and Producing Horizons—Gulf Embayment Province

System	Formation	*Balcones Fault*		*Sabine–Ouachita*		*Reynosa Escarpment*		*Salt Dome*	
		Thickness	*Sands*	*Thickness*	*Sands*	*Thickness*	*Sands*	*Thickness*	*Sands*
Quaternary	Pleistocene	..	..	..	..	..	..	1,000	..
Tertiary	Pliocene	..	..	..	..	450	..	2,000	..
	Miocene	..	..	..	..	1,300	Oakville	2,500	various
	Oligocene	..	..	..	..	1,000	Saxet, Refugio	4,500	various
Eocene	Jackson	..	..	500	..	1,500	Many sands	800	..
	Claiborne	..	..	1,200	..	2,700	Many sands	2,000	Clay Creek
	Wilcox	450	..	500	..	..	..	2,500	„
	Midway	300	..	400	Urania	..	..	1,000	..
	(Unconformity)								
Cretaceous	Navarro	600	Nacatoch	600	Nacatoch	..	..	..	..
	Taylor	1,000	..	600	Annona, &c.	..	..	..	..
	Austin	450	Austin	300	Tokio, Blossom	..	..	..	..
	Eagle Ford	350	..	50	..	..	..	..	..
	Woodbine	200	Woodbine	100	Woodbine	..	..	..	Boggy Creek
	(Unconformity)								
Comanchean	Washita	300	..	600	..	..	..	..	..
	Fredericksburg	500	Edwards	1,000	..	..	..	..	..
	Trinity	800	Paluxy	4,000	Glen Rose	..	..	..	..

The principal structural features of the province were no doubt initiated at that time. Two wells in McLennan County show that about one-third of the total displacement along the Balcones Fault in that area was produced then. The common absence of the Woodbine and Eagle Ford formations from the Sabine Uplift and the Ouachita Uplift (Monroe and Richland fields in Louisiana and northward into Arkansas) show clearly that these important structures had been started.

Earth movements during the Cretaceous period were infrequent and subdued. The most important break came at the close of Navarro time, when a widespread retreat of the seas brought many structures into the sphere of subaerial erosion. Such have been described from the *Dixie oil-pool* on the Sabine Uplift and the *Richland gasfield* on the Ouachita Uplift. At these places renewed deformation produced angular unconformities. During ensuing Midway time there was another period of relative stability. But quite the opposite is true of the remainder of the Tertiary. Very great variations in the thickness of the Wilcox indicate continued uplift of the positive areas such as the Sabine Uplift. Differential uplift and deformation were marked in Claiborne time. It is also noticeable in the succeeding Oligocene and Miocene epochs. Many of the salt-domes show the effects of these spasmodic recurrences of upthrusting by a thinning of the strata across the top.

Balcones Fault District. The Balcones Fault Zone has

therefore surface indications of prominent structural lines in the subsurface.

The producing horizons in this district are listed in the table of formations given above. The most prolific is the *Woodbine sand* which appears at the base of the Cretaceous system. Next in importance is a limestone in the Comanchean Fredericksburg division called the *Edwards lime*. The upper 25 to 35 ft. of this limestone are porous and contain oil in the *Luling*, *Joe Bruner*, *Salt Flat*, and *Darst Creek* structures. It will be noted that these are in the southern part of the area, whereas the Woodbine produces only in the northern part. In the district some small production has been obtained from various formations in the Cretaceous system. The *Austin chalk* produces some oil from cavities associated with the fault zone in the *Joe Bruner* and the *Darst Creek* fields. The overlying Taylor contains several producing horizons in different parts of the district. Perhaps the most interesting is the altered igneous rock (serpentine) which produces at *Thrall* and at *Lytton Springs*. Several thin sand lenses which lie close to the top of the Taylor produce some oil and gas at *Corsicana*. In the Navarro there are also sand lenses which are correlated with the Nacatoch sand so important farther east. In this district they have produced considerable amounts of gas and some heavy oil at *Powell*.

Sabine–Ouachita Uplifts District. The Sabine Uplift is a very large and broad dome-like structure in north-eastern

Louisiana and north-eastern Texas. The largest field in the world is located on its western flank, the famous *East Texas* field. Other famous pools on it are the *Caddo*, *Haynesville*, and *Homer* oil-pools. On its southern flank lie the *Bull Bayou* and the *Zwolle* pools. The producing horizon in the East Texas field is the *Woodbine*, but in the others higher strata contain the oil and gas. The *Tokio sands* near the base of the Austin chalk formation produce oil in the *Dixie* and the *Caddo* pools. The '*Blossom*' *sand*, by some placed in the Austin and by others in the Taylor, yields oil at *Homer* and *Haynesville*. It is also an important source of gas. Higher in the Taylor lies the *Annona chalk* which accounts for some of the oil at *Caddo* and probably some at *Zwolle*. In the latter field production is very erratic and comes from a cavernous marly limestone which probably is in part the Marlbrook. The most consistent and largest producer of oil and gas is the *Nacatoch* sand of the Navarro formation.

The Ouachita Uplift trends north-west and south-east from south central Arkansas into north-eastern Louisiana. On it the very prolific *Smackover* and *El Dorado* fields of Arkansas are located as well as the *Monroe* and *Richland* gasfields of Louisiana. In the former oil is found within the *Nacatoch*, *Taylor*, and *Tokio* formations. The two large gas-pools derive their gas from the *Annona chalk* and some porous tuff beds within the *Tokio*. At *Richland* some gas-wells have been drilled into the deep sand within the *Glen Rose* portion of the Trinity. The same horizon has also furnished some gas in several gas-pools of the Sabine Uplift (*Bethany* and *Cotton Valley*). By contrast the oil and gas at *Urania* comes from the topmost portion of the *Wilcox* of Tertiary age.

Reynosa Escarpment. In southern Texas (often called south-west Texas) one of the well-cemented Pleistocene formations called the Reynosa makes prominent escarpments. Because the early fields were discovered close to the western edge of this escarpment the district was named after it. Now the pools and fields have spread out towards the north and especially towards the north-east into Duvall, Jim Wells, Live, Bee, and Victoria Counties, so that the name is no longer applicable. In this district many sands produce oil or gas or both. Gas is more common in the upper sands and oil in the lower ones. The highest sands occur in the Oakville of Miocene age. The *Frio* clay of Oligocene age contains important sands at *Refugio* and *Saxet*. The *Jackson* of Eocene age is the most productive at the present time. It contains sands in the *Fayette* sandstone (*Cole* and *Driscoll*), the *McElroy* member at *Government Wells* and *Mirando*, and the *Cockfield* member at *Pettus* and *Jacob*. The deepest sands found to date are in the Claiborne. The *Yegua* member produces at *Tuleta* and at *Conroe*. The *Cook Mt.* member seems to be the producing horizon at *Jennings*. Most of the oil from the Laredo part of the district is derived from the *McElroy*, and most of the gas from the *Cole* sand 170 ft. higher in the section.

Salt Dome District. The Salt Dome district takes in all of southern Texas and southern Louisiana as well as a synclinal area in eastern Texas and a similar one between the Sabine and Ouachita Uplifts in Louisiana. Since the Gulf geosyncline deepens towards the south-east, all formations thicken notably in that direction. Furthermore, younger strata crop out towards the south-east, and for that reason the stratigraphy of the 'Interior Domes' resembles that of the Balcones Fault and Sabine Uplift districts, while the southern domes have a section similar to that of the Reynosa district. In the latter the Pleistocene and Pliocene series are very thick, but carry no oil. The *Miocene*, on the other hand, is at present the most important, because it produces about 50% of the oil. Many sands are involved, and these have local names. Because of their lenticular nature they cannot be correlated from one field to another as a rule. Similarly, the *Oligocene* contains many productive horizons, and these account for approximately 40% of the oil from the district. The remainder comes from sands in the Eocene or the cap-rocks of the salt-domes. The only dome which has production from the Eocene at present is the *Clay Creek dome* in Washington County. The only 'Interior Dome' which produces oil is the *Boggy Creek dome* in Cherokee County, and it produces from the basal Cretaceous *Woodbine sand.*

Relation of Oil Accumulation to Structure.

In this province the importance of unconformities stands out prominently. Almost without exception the prolific horizons can be shown to be either above or below marked unconformities in the stratigraphic sequence. In the *Balcones Fault district* the most oil comes from the *Woodbine* which lies unconformably above the Comanchean strata. The second most important horizon is the *Edwards* limestone, which has an unconformity above it. Structural deformation accounts for the unconformities. In this case normal faults raised the strata on the east side, allowing calcareous rocks to acquire porosity and remain in the zone favourable for oil accumulation. In those structures in which porous sands were deposited above the unconformity the oil continued to accumulate and remained trapped in them. Several pools show clearly that some migration has taken place along the fault, because small saturated zones were formed in higher strata carrying oil of the same physical character.

In the Sabine and the Ouachita districts unconformities are well marked. On the high parts of the uplifts the lower formations of the Cretaceous, for instance, are missing, and oil has accumulated in the next overlying basal sands (*Tokio* and *Woodbine*). The unconformity between the Cretaceous and the Tertiary is indicated also by missing formations. In some pools the *Nacatoch* lies at this level and produces the oil. In others the *Annona* chalk appears at the unconformity level. Here also it should be added that deformation has played an important part, for it raised the strata to structurally high elevations above surrounding areas. Small domes and faulted domes are characteristic of the district.

In the *Reynosa district* the controlling feature seems to be porosity in sandstones which are elongated in the direction of the shorelines of the time. Much evidence points to the conclusion that many accumulations have taken place in *barriers* or *off-shore bars* such as characterize the present coastline. A few years ago it was believed that faults bounded the producing areas on the west, but now only one example of that kind is definitely known (Carolina–Texas). A search for such shoreline trends has been rewarded in recent years with the discovery of Conroe and Raccoon Bend besides many pools of smaller magnitude; a number of maps have been published for portions of the Reynosa district, and they usually show the gulfward dipping monocline modified by small noses and ravines. Brace interprets the latter as probably due to irregularities in thickness of the sand rather than due to structure. He states, furthermore, that the gas tends to accumulate in the up-dip areas where the porosity of the sand is reduced.

In the *Salt Dome district* oil occurs in sands flanking the

salt mass, secondly in the porous calcareous cap-rock, and thirdly in sands arched above the salt mass. In each case the porous horizons were elevated by the repeated upthrusts of the growing salt mass, causing them to lie at a structurally high position. Simultaneously, oil-producing material was incorporated within their pore spaces, where it was trapped by impervious clays later.

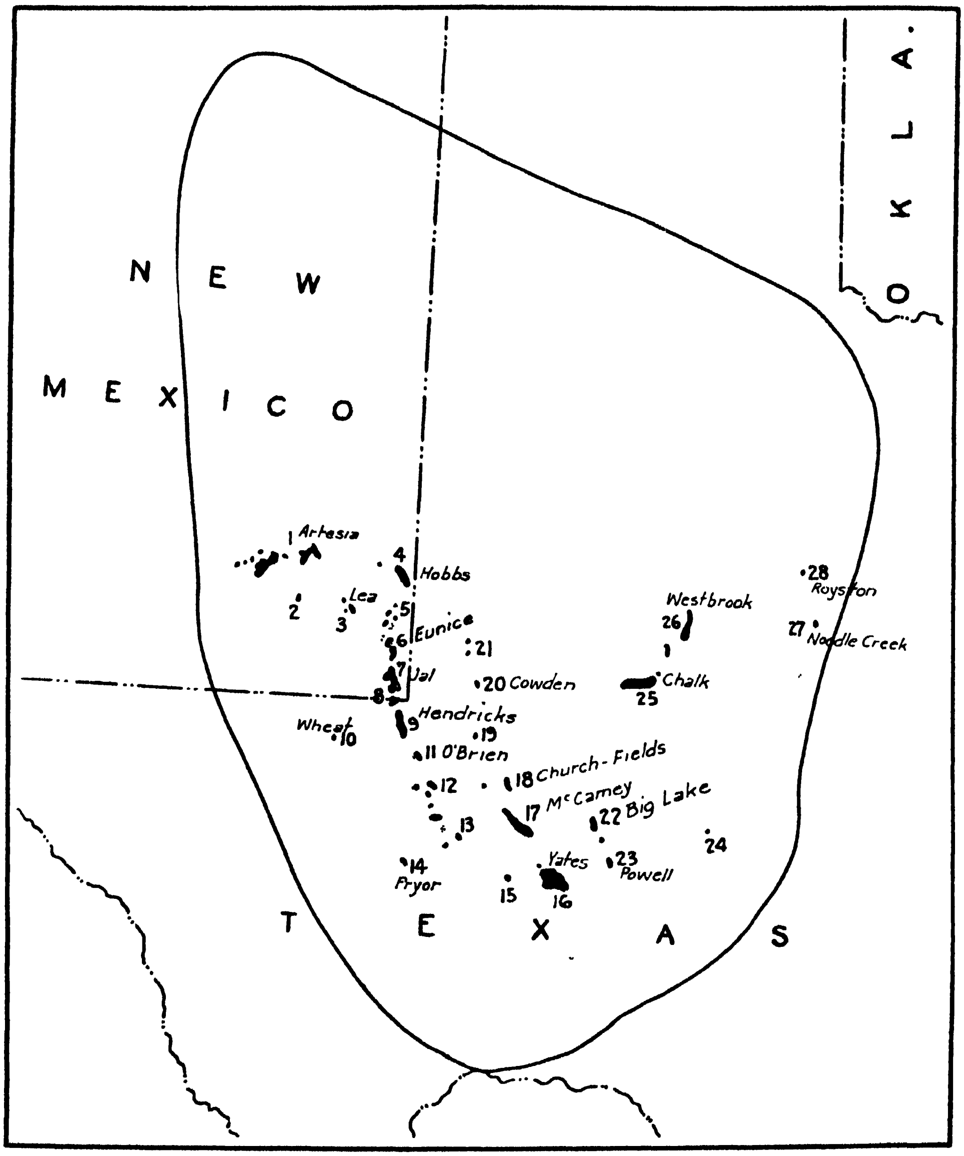

FIG. 9. West Texas Basin.

Future Reserves.

The Gulf Embayment province probably contains the largest reserve supply of oil in the United States. It has already produced practically 3 billion barrels. Of this total the Balcones Fault district has contributed 416 million, the Sabine–Ouachita Uplifts district 1,600 million, the Reynosa or South Texas district 104 million, and the Salt Dome district 1,060 million barrels. The first-named district is fairly close to exhaustion and can hardly be expected to furnish more than 120 million barrels in the future. The Sabine–Ouachita district is about 50% exhausted and will supply close to 1,500 million barrels. The South Texas district is just beginning to show its possibilities and can confidently be counted on for at least 650 million barrels. While the Salt Dome district is closer to exhaustion, the author believes that future discoveries will provide at least 500 million, and reserves in sight another 750 million. A rather moderate estimate for the whole province, therefore, shows future reserves of nearly 3½ billion barrels.

Some bonanzas are the Powell pool (122 million), Mexia pool (93 million), East Texas (800 million), Caddo (138 million), Spindletop (120 million), Humble (117 million), West Columbia (77 million), Sour Lake (76 million), Goose Creek (73 million), Haynesville (63 million), and Homer (61 million). These figures indicate only production up to date. On a per acre basis these amounts reveal a number of fields with over 100,000 barrels per acre.

X. The West Texas Basin Province

When oil was discovered in Mitchell County of western Texas in 1921 no excitement was aroused among oil men. Two years later the now famous Big Lake pool in Reagan County was discovered. It also failed to create interest

because it was generally believed that Permian rocks known to be thick there could not contain large accumulations of oil. Wild-catting continued, however, and in 1925 a large pool was found in south-western Upton County, the McCamey pool. Meanwhile, in 1924 the Artesia pool in New Mexico had also come into production. The most remarkable pool in the province was discovered in 1926 on the Yates ranch in Pecos County.

Tectonic Setting.

These pools are located in a broad, shallow basin which lies west of the Bend Arch described in § VIII. On the south it is bordered by the older Palaeozoic rocks which crop out in the Marathon region. The western rim is marked by prominent mountain ranges in which the producing horizon of the basin makes elongated limestone ridges. Within the deep portion of the basin there is a 'central platform' having its apex under the Yates pool and trending north-west from there. The oil-pools located along the line between Upton and Crane County and thence north-westward lie along the eastern side of this platform. The other prominent line of pools through Ward and Winkler Counties towards the Hobbs pool in New Mexico lie along the western side of the platform.

Stratigraphy and Producing Horizons—West Texas Province

System	*Formation*	*Thickness*	*Producing horizons*
Tertiary .	..	0 to 300	..
Comanchean	..	300–800	..
Triassic .	Dockum	100–600	..
			(Unconformity)
Permian .	Evaporite	650 to 1,900	Yates, 'Brown Lime' at Hobbs Bowers and Big Gas Pay at Hobbs
	Big Lime	2,000	'Brown Lime' at Yates and Hendricks Texon Pay at Big Lake 'White Lime' at Hobbs &c.
Pennsylv.	..	3,300	Crinoidal at Big Lake
			(Angular unconformity)
Sil.-Devon.	Hunton?	70	..
Ordovician	Sylvan	100	..
	Viola	80	..
	Simpson	120	..
	Ellenburger	..	'Deep Pay' at Big Lake

This important buried 'high' is characterized by steep dips to the north-east and the south-west (at least in the southern part). Stratigraphic evidence indicates that it was formed during Permian time by strong upthrust movements. A fault has been found in the pre-Triassic rocks along the south-east side of the Yates pool with a downward displacement to the east. In the Big Lake pool, which lies on a parallel fault block to the east of the central platform, there is a similar pre-Triassic fault. The pronounced thinning of Late Permian evaporite materials across the structures also indicates Early Permian deformation. At Hobbs it has been estimated that one-third of the total amount of deformation shown in the beds is due to this early diastrophism.

Stratigraphy.

The table above shows the sequence of rocks which is customarily penetrated in the deep wells on structure. The thicknesses shown are averages for the abbreviated section found in the oilfields. Much greater thicknesses have been found in the basins away from the structures. The Comanchean rocks form an unconformable blanket over the older rocks, while the Triassic rocks form a wedge thickening towards the west. A broad regional unconformity separates them from the Permian strata. The latter consist essentially of two units, an upper *evaporite series* and a lower *dolomite series*. The upper series is composed of several oscillatory sequences of the materials usually formed in desiccating seas. Red shales, anhydrites, and salt alternate in such a way that three well-marked zones of salt may be distinguished. In one of these cycles polyhalite was precipitated. Strange as it may seem, oil and gas in commercial quantities are found within this series. At Yates, for instance, the *Yates sand* appears 500 ft. above the base. In the Hobbs pool there are three producing horizons in the evaporite series. The highest is called the *Brown lime*. It carries gas and appears 1,200 ft. above the base. A few hundred feet lower the *Bowers sand* contains showings of oil and gas, and 500 ft. still lower lies the '*Big Gas Pay*'. The potentialities of these horizons are not known because drilling is carried on to the Big Lime.

The *Big Lime series* varies from 1,800 to 2,200 ft. where it has been penetrated by the drill. It consists essentially of dolomite, but contains sandy streaks and bentonitic material. The top portion is usually separated from the rest as the 'Brown Lime' on account of its colour. Very often this upper zone is characterized by the presence of numerous sand grains. In the *Yates pool* the brown sandy lime is 130 ft. thick and in the *Hendricks pool* from 180 to 350 ft. thick. It may contain oil as at Yates or considerable gas as at Hendricks. However, much larger quantities of both are found below it.

The discovery of detrital material near the base of the 'Brown Lime' in the Hobbs pool shows that an unconformity separates it from the 'White Lime' below. Usually the top of the latter is dense and hard and thus forms a caprock for the porous and cavernous rock below. At Hobbs there are two porous zones, one of which is 80 ft. thick and the other (the 'Capps' zone) somewhat thinner. At Yates there appear to be five zones within a vertical distance of 125 ft. (the total porous zone including 100 ft. of 'Brown Lime' being 225 ft.). At Big Lake the porous zone lies 40 ft. below the top of the 'White Lime' and is about 30 ft. thick. Much evidence is now at hand which shows that the porosity of this dolomite is due to solution.

Lower zones in the 'Big Lime' have not been explored on the central plateau because of the large amount of oil at the top. However, in the north-eastern part of the basin at *Westbrook* in Mitchell County several porous zones have been found at 900 ft. and 1,500 ft. below the top. Still lower 'pays' have been discovered at *Big Lake*. A *crinoidal limestone* which appears to be a basal Pennsylvanian formation lying upon the angular unconformity which separates it from the Ordovician has produced some oil. The Ordovician rocks dip away steeply from under the unconformity so that a thickness of several hundred feet is truncated. Some geologists believe that the *Hunton* limestone of Siluro-

Devonian age appears in the older sequence. Below it lie the *Sylvan, Viola, Simpson*, and *Ellenburger* formations in the same order and with similar lithologic characteristics as in the producing area of Oklahoma. The Ellenburger dolomite seems to carry the oil which is found in the deep wells (8,250 ft.).

Cause of Oil Accumulation.

Although a number of the producing horizons described above are capable of furnishing much oil and a great deal of gas, the outstanding one is the porous zone in the '*Big Lime*'. It has supplied not only some of the largest wells in the world (up to 205,000 bbl. per day), but also shows potentialities of very large per acre production. The 16,000 acres in the *Yates pool* have produced 224 million barrels (end of 1936), which means nearly 14,000 barrels an acre. It is reasonable to assume that this figure will be more than doubled, judging by the performance of the wells. The *Big Lake pool* shows nearly 25,000 barrels per acre for the 'Big Lime' pay and 33,000 barrels per acre for both pays.

As pointed out above, the 'Big Lime' is related to a prominent unconformity which indicates uplift and erosion before the evaporite series was deposited to make an effective cap-rock. This also explains the great porosity in the dolomite, because it was doubtless subject to the solution effects of circulating ground water. The relative elevation of the central plateau and its string of 'highs' provided the necessary structural relief.

Production Data.

A total of 750 million barrels of oil has been recovered from the various pools in the West Texas Basin. Over 90% of this amount has come from the pools in the State of Texas where the Yates pool alone has accounted for nearly 224 million and the Hendricks pool about 180 million. Another 100 million were derived from the pools in Crane and Upton Counties (Church, Fields, McElroy, McCamey, Taylor). The other bonanza pools are the Big Lake with 80 million and the Chalk pool with 60 million barrels yield to the end of 1935. In New Mexico the bulk of the oil has come from the Hobbs pool, which is now producing 12 million barrels annually and has a total of nearly 65 million to its credit.

A large reserve is still available from the proven pools, and 500 million barrels seems a reasonable estimate. Allowing for the probability that the province is less than 50% explored, one must assume that somewhere between one-half and one billion barrels of oil lie concealed in undiscovered structures.

XI. The Rocky Mountain Geosyncline Province

The Rocky Mountain geosyncline was best developed in Mesozoic time. It occupied all or large portions of Montana, Wyoming, Utah, Colorado, Arizona, and New Mexico. The bounding land area on the west had its axis along the 115° parallel of longitude, but varied somewhat in size and height from time to time. For instance, during Triassic time practically all of Montana was part of the land area and subject to erosion. The significance of this will be apparent when the oilfields of the Sweetgrass arch are discussed. Subsidence of the geosyncline was very rapid and great along the eastern border of the land area throughout the Mesozoic, but reached a climax in Cretaceous time. The thickness of Cretaceous sediments is measured in thousands of feet and exceptionally, as in western Wyoming, as much as 14,000 ft. is recorded. (Fig. 10.)

Tectonic History.

At the close of Cretaceous time and during the early portion of Tertiary time these sediments were greatly deformed by orogenic disturbances. Vertical displacements involving 28,000 ft. are characteristic results of this deformation. As the older rocks came up on the borders of huge fault blocks they were stripped of their overburden and the detritus gathered in the large basins between them as Tertiary sediments. Such basins are particularly well developed in Wyoming and western Colorado. They are named after the principal river which flows through the basin. In north-eastern Wyoming lies the *Powder River Basin*, in north-western Wyoming the *Bighorn Basin*, and in south-western Wyoming the *Green River Basin*. In north-western Colorado lies the *Uinta Basin* and in north-western New Mexico the *San Juan Basin*.

Structures.

Each of these basins has a zone of folded rocks around the periphery in which the strata are arranged in short *en échelon* anticlines with steep dips. The Bighorn Basin illustrates this arrangement most perfectly, while the other basins depart from the ideal grouping more or less. For instance, in the Powder River Basin and the Julesburg Basin the high anticlines are found only on the west side. In other words, the anticlinal zones are complementary effects associated with the mountainous tracts on their borders and are better understood when examined in that light. (Parallel *en échelon* fault blocks.)

The important structures in Montana are not so simply classified. In the centre of the State there is a prominent plateau-like structural feature called the *Big Snowy anticlinorium*. It is bounded on the north as well as the south by very asymmetrical anticlines. Some of these have been found to carry oil and gas. Another large structural feature lies in the northern part of the State somewhat west of the centre. It has been named the *Sweetgrass Arch* and harbours the most productive fields of the State. In the extreme eastern part of the State lies the *Cedar Creek anticline* (sometimes called *Baker-Glendive*) on which only gas has been found up to date.

Distribution of Oil-pools.

The productive oil- and gas-pools extend from the Canadian border through Montana, Wyoming, and Colorado into north-eastern Utah and north-western New Mexico. On account of the steep dips of the anticlines most of the pools (now numbering over 100) are separate and distinct. The largest number of pools and the most prolific ones are located in Wyoming within the confines of five basins. The Colorado pools are located in the Uinta, Green River, and Julesburg basins. Practically all the pools in the Uinta Basin are gas-pools, but those of the Julesburg Basin are primarily oil-pools. The San Juan Basin in New Mexico contains three oil- and two gas-pools at the present time.

Stratigraphy.

Because of the uniform geological history of this province the stratigraphy is similar in the various districts. The table below summarizes the important formation names and also shows the producing horizons. In

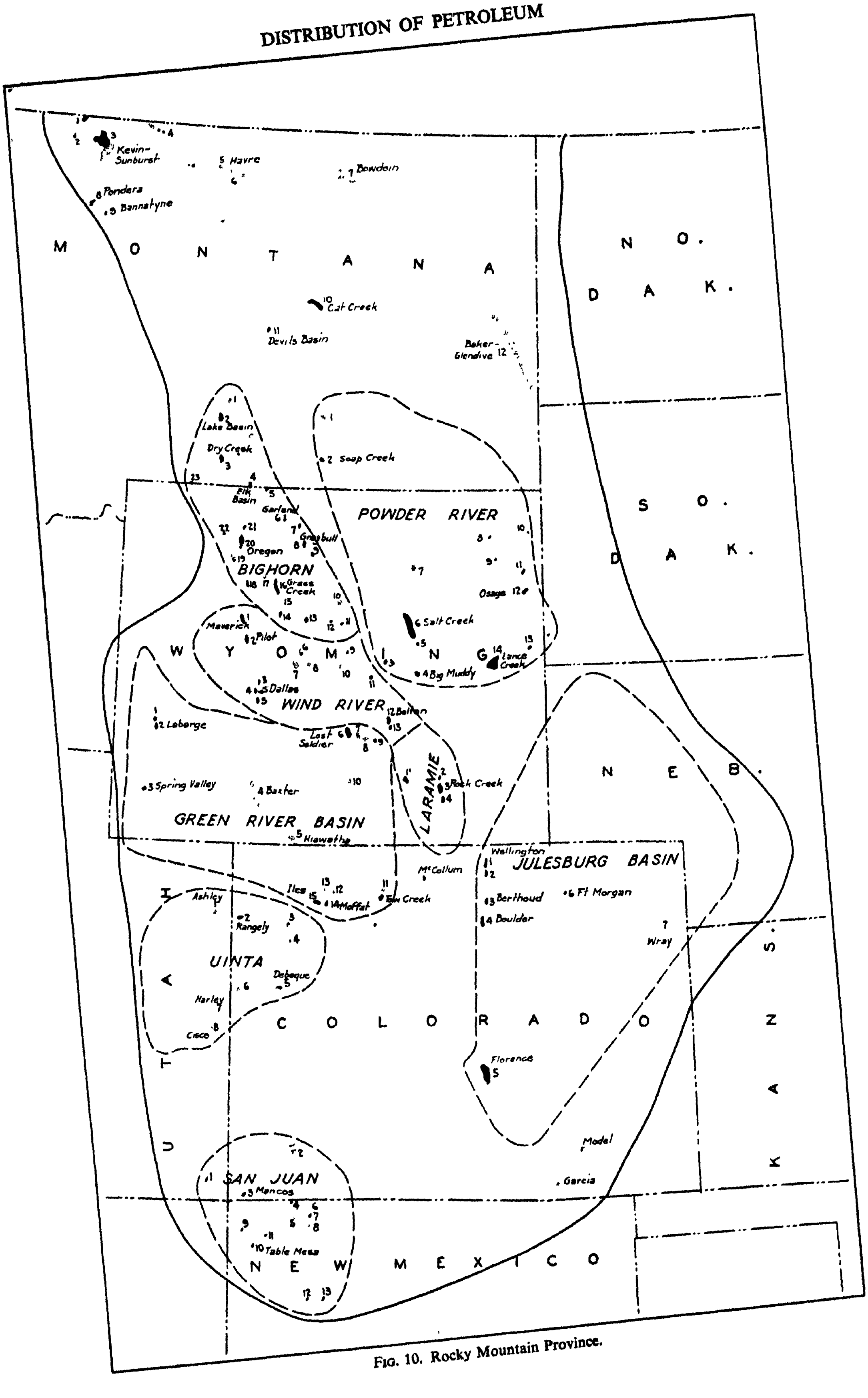

Fig. 10. Rocky Mountain Province.

each of the districts there is a great thickness of Tertiary sediments in which no commercial quantities of petroleum occur. The Cretaceous system is usually divided into the Laramie, Montana, Colorado, and Dakota divisions. The *Montana* consists of shales in which there are occasional sandy zones and lenticular sandstones. One of these, the *Shannon*, produces small quantities of oil or gas in three pools and another, the *Eagle*, gas in four pools.

The Colorado shales also contain sandstones, among which the *Frontier* group is outstanding. Most of the oil produced in Wyoming up to date has come from the *Wall Creek sands* of the Frontier group. In Montana oil has been found in the Frontier at *Elk Basin* which lies in the Bighorn Basin. It has produced gas at *Big Lake* and at *Bowdoin*. In Colorado the Mancos shale yields oil at *Rangely* in the Uinta Basin and at *Tow Creek* in the Green River Basin. Shale oil has also been found in the remarkable *Florence* pool of central Colorado. The production is long lived and comes from the *Pierre* shale.

Next in importance to the Frontier sands are those of the *Dakota* zone. Three well-defined levels of sands occur in this zone. At the base lies the *Lakota* or basal Cloverly which is usually considered to be of Comanchean age. The true *Dakota* lies about 150 ft. higher in the section and marks the base of the Upper Cretaceous. It is succeeded by the *Muddy sand* within the Thermopolis or lower portion of the Colorado shales. In every basin or district of the Rocky Mountain province, with the exception of the Wind River Basin, one of these three sands is outstanding either as a producer of oil or of gas. In fact most of the large gas-pools derive their gas from this zone. In Montana the *Cat Creek sand* in the centre of the State and the *Sunburst* in the north-western part of the State are correlated with the Dakota zone.

In pre-Cretaceous rocks practically every system can boast of one or more producing horizons, but these are limited to very local areas. The *Morrison* produces at *Grass Creek* in the Bighorn Basin and a little oil at other places as, for instance, at *Salt Creek*. Gas was found at this horizon in the *Big Sand Draw* pool near the middle of the Wind River Basin. In the Jurassic there are several sands near the base usually called either *Sundance* or *Nugget*. They produce oil at a number of pools in the *Wind River Basin*, *Lost Soldier* in the Green River Basin, and at *Salt Creek* in the Powder River Basin. In north-western Colorado some production in the *Moffet* and *Iles* pools comes from the Sundance. The *Chugwater* of Triassic age produces oil at *Bolton* in the Wind River Basin.

Oil is obtained from the *Embar* limestone of the Permian, the *Tensleep* sandstone of the Pennsylvanian, and the *Madison* limestone of the Mississippian. The principal production from the Embar is found in the pools along the western side of the Wind River Basin, but a few pools in the Bighorn Basin also derive oil from this horizon. The *Tensleep* produces over a much greater area. Two pools in the Bighorn, one in the Wind River, two in the Green River, and three in the Powder River Basin of Wyoming as well as the Rangely pool in north-western Colorado derive some oil from this thick-bedded, even-grained sandstone. Deeper drilling in other parts of the province will undoubtedly uncover more production in it. The *Van Duzen* sand of the *Devils Basin* and the *Soap Creek* pools of southern Montana lies in the *Quadrant* formation of Pennsylvanian age.

Stratigraphy and Producing Horizons in Rocky Mountain Province

		Wyoming		Montana		Colorado		New Mexico	
System	*Formation*	*Thickness*	*Producing horizon*	*Thickness*	*Producing horizon*	*Thickness*	*Producing horizon*	*Thickness*	*Producing horizon*
Tertiary .	.	2,000	.	3,000	..	5,000	.	2,000	..
Cretaceous .	Laramie	1,500	..	..	..	1,500	..	..	..
	Montana	2,000	Shannon	1,000	Eagle	4,000	Pierre	2,000	..
	Colorado	1,200	Wall Creek, Frontier	2,000	Mosby, Frontier	5,000	Shale	2,000	..
	Dakota	200	Muddy, Dakota, Lakota	200	Cat Creek, Sunburst	300	Muddy	450	Dakota
Comanchean .	Morrison	300	Morrison	250	..	500	..	200	..
Jurassic .	Sundance	400	Nugget and Sundance	300	..	900	Sundance	1,000	..
Triassic .	Chugwater	800	..	800	..	900	..	1,500	..
Permian .	Embar	200	Embar	200		100	..	1,300	..
Pennsylvanian	Tensleep, &c	300	Tensleep	200	Van Duzen, &c.	900	Tensleep	2,000	Magdalena
Mississippian	Madison	600	Frannie	700	Campbell, &c	..	.	..	..

The *Madison* limestone is the outstanding petroliferous unit in the Sweetgrass Arch district of north central Montana. There it is often referred to as the *Campbell pay* in the *Kevin-Sunburst* field where it was first found. The upper 10 to 20 ft. of the limestone were rendered porous by solution during the long interval of time between the end of the Mississippian and the later Jurassic when the *Ellis* formation was laid down. In these cavities the oil has been trapped. Elsewhere the results of drilling to the Madison have been disappointing. At *Garland* and *Frannie* in the Bighorn Basin some oil occurs throughout a thickness of 800 ft. of the limestone.

Relation between Structure and Production.

In the typical pools of this province (and this includes 90% of present pools) oil and gas occur only on the high portions of anticlines or domes. Here the anticlinal theory of oil accumulation finds its most convincing illustrations. Gravitational separation of oil, gas, and water is almost perfect. In some pools oil and gas extend down to the lowest closing contour, but in most pools they occupy only a portion of the closed structure. In many structures, unfortunately, oil or gas are entirely wanting, as the wildcatter has found out. In a general way only gas occurs in the higher sands, both oil and gas in the sands of the Lower Cretaceous, and oil only in the lower horizons.

The importance of unconformities in the sequence is not known at present. Since drilling is rarely carried on away

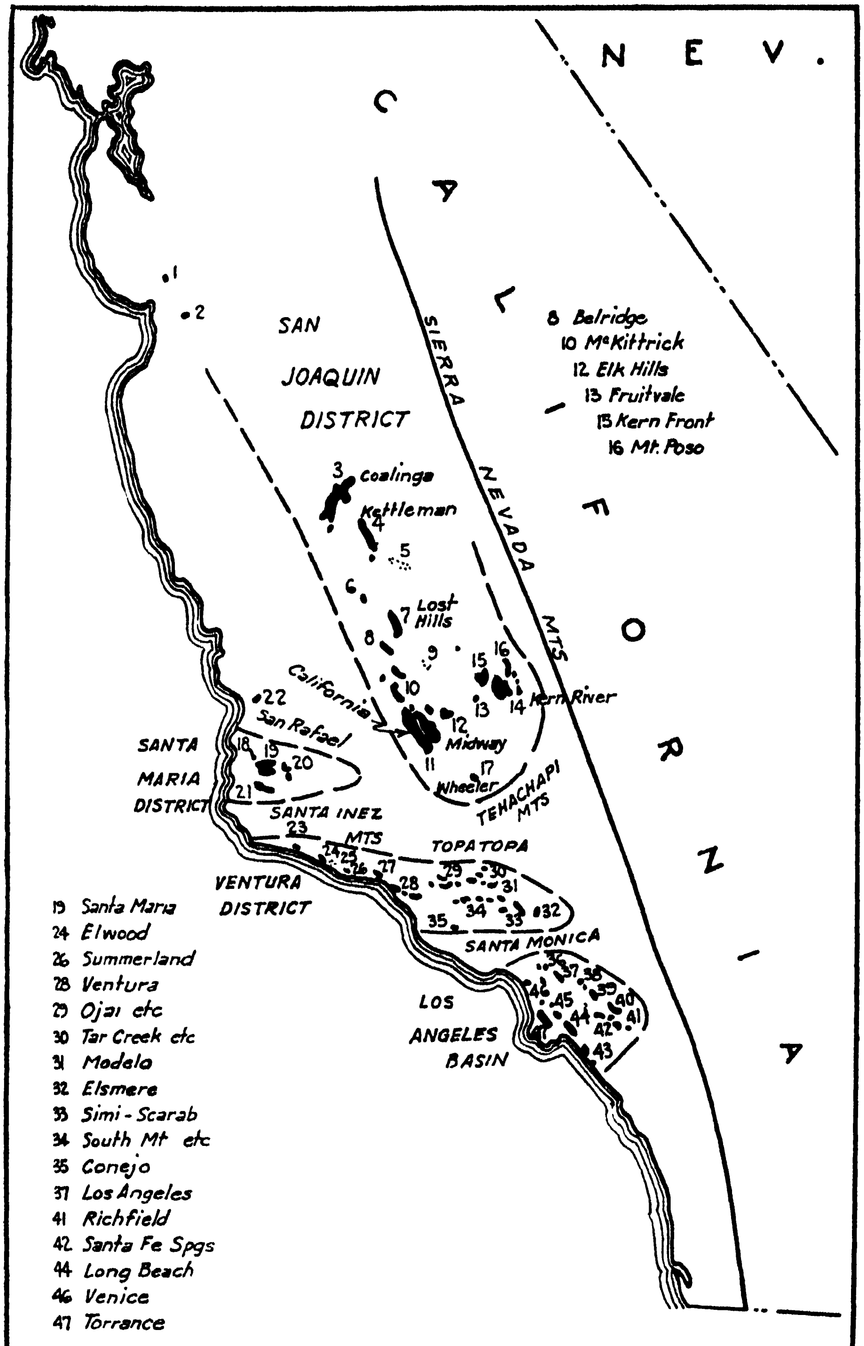

FIG. 11. Oilfields of California.

The trend of the large wells is nearly rectilinear or gently sinuous, thus reflecting the trend of the underground caverns. The behaviour of certain wells indicates intercommunication for considerable distances. Dobbin and Erdman [5, 1934, p. 708] describe several wells which directly influenced the flow and the production of other wells located as far as 2 miles away.

Exceptional Structural Control. In the pools that lie along the north and east fringes of the province the influence of anticlinal structure is subdued or wanting. In the Sweetgrass arch, for instance, the *Bannatyne* and *Pondera* fields lie well down on the northward plunging slope of the structure. Still farther north lies the *Kevin-Sunburst* group of fields. Here, however, a subordinate dome may have had some influence on accumulation. More probably the relief of the dome facilitated the work of ground waters and favoured the formation of solution channels. On the east side of the Powder River Basin a few oil- and gas-pools have been found. In one of these, the *Osage* pool, the oil has been trapped on two terraces separated by a zone of steeper dips. These pools are located on the west side of the Black Hills, an isolated mountain uplift which differs greatly from the type found farther west. The *Florence* pool in central Colorado is located in a syncline. Oil is produced from crevices in the Pierre shale throughout a considerable vertical range.

Production Statistics.

Up to the end of 1935 this province has accounted for a total of slightly less than 500 million barrels of oil. More than three-fifths of this total should be credited to five pools in Wyoming. They are the *Salt Creek* pool in the Powder River Basin, the *Grass Creek* pool in the Bighorn Basin, the *Big Muddy* in the Powder River Basin, the *Lost Soldier* in the Green River Basin, and the *Rock Creek* pool in the Laramie Basin. These five are not equal in rank because Salt Creek produced 10 times as much as the second or a total of 261 million barrels. By projecting the present production curves it will be seen that hardly more than 200 million barrels are now in reserve. Only a few new pools can be expected in the future, because all prominent known structures have been tested. Some slight additional reserves will be secured by deeper drilling. The most likely spot for a large pool is in the Julesburg Basin of eastern Colorado.

from the steeply dipping structures, evidence of thinning of formations cannot be established. A few cases are on record where the subsurface structure is steeper than the structure at the surface (Davies [5, 1934, p. 690]). In the lower strata evidence of unconformities is more apparent. For instance, in the Embar formation the main pay is found from 25 to 125 ft. below the top of the limestone at a level characterized by chert residues and phosphate. These features imply unconformable relations. In the Madison limestone the evidence is complete. For not only is there a large gap in the record, but the action of the wells implies solution channels connected with an unconformity.

XII. The Pacific Geosyncline Province

The Pacific Geosyncline Province lies west of the Sierra Nevada Mountains and their northern continuations through Oregon and Washington. Oil and gas have been discovered in two of the States involved, California and Washington, but the important fields are limited to the former. In fact, only the southern part of California merits consideration at the present time from the standpoint of commercial production. (Fig. 11.)

Tectonics.

Southern California is broken up by fault block mountains which trend in two directions. The main trend is from north-west to south-east as illustrated by the Coast Ranges southward from San Francisco. They form the western limits of the San Joaquin Valley, the most prominent structural depression in the State. It is closed at the southern end by the northernmost of a series of short disconnected ranges which trend predominantly from east to west. These ranges diverge somewhat towards the Pacific Ocean producing two small wedge-shaped valleys, the Santa Maria valley of Santa Barbara County and the valley occupied by the Santa Clara and Simi Rivers in southern Ventura County. The Santa Inez Mountains, which produce the unusual deflexion in the California coastline north-west of Los Angeles, also form the boundary between the two valleys described. The Santa Monica Mountains similarly divide the Ventura Valley from the Los Angeles Basin in which the influence of the north-west trend is again manifest.

San Joaquin District. The oilfields of California, therefore, fall naturally into four districts, named after the valleys with which they are associated. In the northern or *San Joaquin Valley district* the oil-pools are located on subsidiary structures which closely parallel the outer rim of the valley. Beginning with the *Coalinga* pool at the north-west one zone of structures includes the famous *Kettleman Hills* and *Lost Hills* pools. Offsetting this zone in an *en échelon* fashion towards the south-west are the *North Belridge, Belridge, McKittrick, and Elk Hills* pools. West of the latter lies the remarkably productive area known as the *Midway-Sunset field,* which has a homoclinal structure like the Coalinga field. In contrast to these the others mentioned are all located on anticlines. At the southern end of the valley lies the *Wheeler Ridge* anticline. East of the Elk Hills pool and on the opposite side of the San Joaquin Valley lie five pools which are homoclinal in structure. They are the *Fruitvale, Kern River, Kern Front, Round Mountain,* and *Mt. Poso* pools. The last three are known to be faulted and the first two are suspected of being faulted homoclines.

Producing Horizons.

As the table below shows, the important producing horizons in this district lie in the *Pliocene* and *Miocene* series. The outstanding pools associated with each series or formation are listed in the table. Up to date the sands in the lower part of the Pliocene have accounted for the larger half of the production, one pool alone (Midway-Sunset) having yielded nearly 800 million barrels of oil. This has been taken from three zones distributed throughout 1,000 ft. of strata. Deeper drilling in recent years has uncovered vast treasures in the Miocene sands. The middle portion of the Miocene, usually referred to as the *Temblor,* furnishes oil from four zones in the *Coalinga* pool. This formation is productive throughout 1,450 ft. in the North Dome of the *Kettleman Hills,* which suggests that the total ultimate production will be very great. The Temblor formation is made up of alternating layers of silty sands, shales, and coarse sands. Several zones of shaly layers divide the formation up into *three producing sections* in which every layer of sufficient porosity contains oil. Such thick producing horizons account for the unusually high per acre production that characterizes the California fields. No production has been found in Oligocene strata, but one pool has production in *Eocene sands.* A little oil has also been found in the still lower *Cretaceous sands* in the *Coalinga* field.

Santa Maria District. The Santa Maria district consists of three river valleys separated by two anticlinal dividing areas. On the northern anticlinal trend are located the *Casmalia, Santa Maria,* and *Cat Canyon* pools. Production comes mostly from sands in the *Monterey* formation, but in the *Santa Maria* pool some production also comes from the *Vaqueros* at the base of the Miocene. On the southern divide lies the *Lompoc* pool in which the *Monterey* is also the producing horizon. The pools in this district are old ones and were located by means of extensive asphalt seepages.

Stratigraphy and Producing Zones—Pacific Geosyncline Province

	San Joaquin District		*Santa Maria District*		*Ventura District*		*Los Angeles District*	
Series	*Formation*	*Pools*	*Formation*	*Pools*	*Formation*	*Pools*	*Formation*	*Pools*
Pleistocene	Tulare	..	Orcutt	..	Saugus	..	San Pedro	..
Pliocene	Etchegoin	McKittrick	Schumann	..	Pico	Ventura	Pico	Long Beach
		Midway	..	..	..	Rincon	..	Santa Fé
		Kern River	..	..	..	Elsmere	..	Coyote
Miocene	Maricopa	N. Belridge	Monterey	Casmalia	Monterey	Tapo Canyon	Puente	Whittier, &c.
		Wheeler R.	..	Sta Maria	or Modelo	Pico Canyon	..	..
	Temblor	Coalinga	Temblor	..	Temblor	..	Topanga	..
		Kettleman	..	..	..	..	..	..
	Vaqueros	..	Vaqueros	Sta Maria	Vaqueros	Capitan	Vaqueros	..
						Elwood	..	..
Oligocene	Pleito	..	..	..	..	..	..	..
	San Emigdio	..	Sespe	..	Sespe	South Mount	Sespe	..
						Scarab	..	..
Eocene	Kreyenhagen	N. Belridge	..	..	Eocene	Simi	Tejon	..
	Avenal	..	..	..	..	..	..	..

Ventura District. The pools of the Ventura district may be grouped into four trends. The most prominent one of these extends along the ocean shore of southern Santa Barbara County and includes the *Capitan*, *Elwood*, *Santa Barbara*, *Summerland*, *Rincon*, and *Ventura Avenue* pools, the last being by far the most remarkable pool in the whole district. On the north side of the Santa Clara River there are 11 pools, all small and most of them rather old. The best known among them are the *Sulphur Mt.*, *Ojai*, and *Sespe* pools. The structure is not well understood, but the rather intimate relation to the San Cayetano thrust fault and branch faults indicates that fault traps are present. Production comes mainly from Lower *Miocene* and from *Oligocene* sands.

On a trend which seems to be the *eastward continuation* of the *Ventura Avenue trend* lie the *South Mt.*, *Bardsdale*, *Shiels Canyon*, *Torrey Canyon*, *Tapo Canyon*, *Pico Canyon*, *Wiley Canyon*, and *Elsmere* pools. These, like the pools in the Capitan to Ventura trend, are located on anticlines. The *producing horizons* vary greatly, as indicated in the preceding table. *Pliocene* production is most important from the standpoint of total amount, for Ventura Avenue pool alone (in which production comes from 12 zones throughout 8,000 ft. of Lower Pliocene) has accounted for more than half the production from the district. *Upper Miocene* and also *Lower Miocene* sands are quite prolific in certain pools. The most widespread producing horizons occur in the *Sespe* formation of Oligocene age. In one pool (Simi) oil has been found in *Eocene* sands.

The Los Angeles District. The Los Angeles district is bounded on the north by the Santa Monica Mountains, on the east by the Repetto Hills and the Puente Hills, on the south by the Santa Ana Mountains and the San Joaquin Hills. The last four appear on the north-west trend mentioned previously and delimit a more or less quadrilateral area known as the Los Angeles Basin. Paralleling the tectonic trend there are *four lines* or *zones* of *pools*. The easternmost zone includes the *Salt Lake*, *Los Angeles*, *Montebello*, *Whittier*, *Puente*, and *Brea-Olinda* pools. In these the influence of the *Whittier fault* bounding the eastern mountain uplifts is clearly discernible. They involve oil accumulations on the downthrown side of single or multiple faults and usually show a *homoclinal* dip into the basin. The Middle Miocene *Puente* formation is the important producing horizon in this belt of pools, but the Middle and Lower *Pliocene* sands also produce considerable oil.

The *second line* of pools lies a short distance west of the former and includes the *Santa Fé*, *West Coyote*, *East Coyote*, and *Richfield* pools. In all these the structural control of oil accumulation is the *anticlinal* arrangement of the strata. The axes of the Santa Fé pool are so nearly equal that it should be called a dome. This is one of the most interesting pools in California. It covers roundly 1,500 acres and has scored the amazing per acre production of over 220,000 barrels. The oil-producing zones are distributed through a vertical range of 4,600 ft. and are arbitrarily divided into *six Pliocene zones* and *one Miocene zone*. Sandy shales separate the petroliferous zones from each other, and as a rule brackish water occurs in them. The thickest oil zone is the seventh or *Clark zone* divided by geologists into *three members* aggregating 800 ft. in thickness. The other zones vary from 135 to 670 ft. in thickness. The two shallow zones produce oil of 28° and 32° gravity, while the lower ones all carry oil of approximately 34° gravity.

Farther east lies the *Inglewood fault line zone* of pools. It includes the *Beverly Hills*, *Inglewood*, *Potrero*, *Athens-Rosecrans*, *Dominguez*, *Long Beach*, *Seal Beach*, *Huntington Beach*, and *Newport* pools. In these the anticlinal structure stands out prominently, but is modified occasionally by subsidiary faults. It is believed that the faults have not had a controlling influence on accumulation. The oil comes from the *Pliocene sands* for the most part, and in some pools these sands occupy a great vertical range (Long Beach 3,000 ft.). Recent deeper drilling has uncovered *three zones* of oil-bearing strata in the *Miocene* at *Long Beach* and one zone at *Seal Beach*. The westernmost belt of pools includes the *Venice* (Playa del Rey), *Lawndale*, and *Torrance* pools. These differ markedly from the others because of structural peculiarities. At Torrance, for instance, the anticlinal structure is unusually gentle for California, and at Lawndale no structural trap is apparent. Interesting also is the discovery of old (pre-Cambrian ?) schists at a comparatively shallow depth at Venice and at Torrance below the Miocene.

Production Data.

The total amount of oil produced by the California fields up to the end of 1935 approximates 4,460 million barrels. The San Joaquin and the Los Angeles districts share almost equally in this stupendous total, the former accounting for slightly less than 2,000 million and the latter for slightly more than 2,000 million barrels. The Santa Maria district should be credited with 133 million and the Ventura district with twice that amount. In the San Joaquin district the banner field is the *Midway-Sunset* field with nearly 785 million barrels to its credit. It will ultimately produce nearly 1 billion barrels. Its rival will be the Kettleman Hills pool, which has produced slightly over 100 million barrels, but whose ultimate production is now estimated to be 1 billion barrels. A reasonable estimate of future production from all pools in this district other than Kettleman Hills is 1 billion barrels, thus making a total available of about 2 billion barrels.

The *Santa Maria district* is nearly exhausted and can hardly be counted on for more than 50 million barrels. In the *Ventura district* the banner pool is the Ventura Avenue pool. It has produced 75 million of the 280 million total for the district, and may be expected to produce an additional 150 million. Allowing 100 million future reserves for the remainder of the district makes a total of about 250 million. The Los Angeles district has two outstanding pools in Long Beach with nearly 550 million to date, and the Santa Fé pool with 400 million. These two have thus accounted for nearly half of the total production from the district. The future reserves from these two may be estimated at 200 million, and from the remainder of the district about twice that amount. Summing up the future production from all districts we arrive at a probable total of 3 billion barrels. This estimate makes no allowance for new discoveries either of additional pools or of deeper producing zones. The San Joaquin district offers the most promising territory for new pools, and these are likely to be uncovered by geophysical explorations now under way. Such new pools may double the estimates of future reserves as stated above.

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CANADA

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PETROLEUM is produced in Canada from such widely separated parts as New Brunswick, Ontario, Alberta, and the North-West Territories. With the exception of a relatively small production of crude oil from Mesozoic rocks in Alberta, all production comes from strata of Palaeozoic age. In New Brunswick the age of the oil-producing horizons is Mississippian. The Devonian has provided most of the fields and the greatest yields in Ontario, but oil has been produced also from Silurian and Ordovician beds. In Alberta sustained production from Palaeozoic rocks has been obtained only in the Turner Valley field from strata presumably of Late Mississippian age. Shows of oil have been found in Devonian strata in the foothills and in Mississippian beds in southern Alberta, and in the foothills in Turner Valley petroleum also occurs in one Jurassic and three Lower Cretaceous horizons. On the plains, with the exception of the Skiff field, where petroleum is found in marine Jurassic beds, all the production comes from Lower Cretaceous strata. In the Mackenzie River area, 50 miles north of Fort Norman, the producing horizon is Upper Devonian shales.

The petroleum produced in New Brunswick comes from the Stony Creek field near Moncton. The producing horizons are in the Albert formation of Mississippian age. The petroleum presumably originated in shales in the Albert formation, which in part is highly bituminous and shows deposition under relatively quiet conditions in a lake-like expanse of fresh water without any evidence of torrential stream action. The main features of the oil-producing area are: the fresh-water origin and predominantly fine-grained nature of the sediments, their great thickness, considered to be more than 5,000 ft., the absence of conglomerates except at the base of the formation, and the remarkably complicated geological history of this region during the Carboniferous period. It is thought (Bell [1, 1922]) that 'Carboniferous sedimentation was controlled by a definite tectonic system ... of the nature of intermittent but long-continued warpings' and 'proceeded in progressively sinking, structural river valleys separated by progressively rising watersheds'. Subsequent to deposition the Albert formation was folded and subjected to erosion. Younger non-marine sediments were deposited over the bevelled edges so that in many areas, including part of the Stony Creek field, the structure of the Albert formation is concealed. The petroleum occurs on the south flank of what formerly may have been an anticline but which is now truncated northward. The producing horizons are groups of sandstones that seem to hold their relative positions very consistently, but the individual sandstone members may be lenticular and discontinuous.

All the petroleum fields of Ontario (Fig. 1) are in the peninsula bounded by Lakes Huron, Erie, and Ontario. This area is underlain by gently dipping strata ranging in age from Late Devonian to Early Ordovician. Some of the first discovered fields are still the main producers after continuous operations extending over 70 years. The productive strata of these early discovered fields are Devonian rocks, but petroleum also has been produced from both Silurian and Ordovician beds. In this part of Ontario a basal Ordovician arkose lies directly on a surface of Pre-Cambrian rocks at a depth of 3,000 to 4,000 ft. In Romney township, Kent county, some petroleum was produced from this basal arkose, but presumably the rock was merely a reservoir for oil that originated elsewhere. Above the arkose there are Black River and Trenton limestones. The Trenton has not been a prolific source of oil in Ontario as is the case in Ohio and Indiana to the south of Lake Erie, but in the Dover West field, east of Lake St. Clair, petroleum is produced from the upper 300 to 400 ft. of this formation in a narrow eastward trending area that either represents a fracture zone or a sharply defined and broken syncline. It is believed that porosity is the controlling feature here, as the Trenton is generally barren elsewhere where porosity is lacking. The remaining part of the Ordovician above the Trenton has yielded no oil in Canada.

In the Niagara Peninsula the Whirlpool sandstone, 5 to 20 ft. thick, forms the base of the Silurian. This sandstone yielded oil in the Onondaga field of Brant county, but the production was very small. The Whirlpool sandstone is considered to be an aeolian deposit [1, 1922] and, like the basal arkose of the Ordovician, is a reservoir for oil that is not indigenous to this horizon. The Silurian strata immediately above the Whirlpool sandstone, or its correlatives in the north and west, are very variable in character and with a thickness not exceeding 200 ft. They are overlain by limestones and dolomites, the upper member of which is the Guelph dolomite. The top of the Guelph is an erosion surface and on it rests a variable succession of beds belonging to the Cayugan group, the lowest member of which is the Salina formation. The Salina locally contains salt and gypsum but as a whole consists of interbedded dolomites and shales, the dolomites of which are indistinguishable in well samples from those of the Guelph, which are thought to have been deposited in a partly enclosed sea under conditions of excess salinity. Petroleum occurs in these dolomite beds at the base of the Salina or the top of the Guelph, particularly in the now exhausted Leamington field, Essex county, and in the still active Tilbury and recently discovered Dawn fields, Kent county. All fields are anticlines, and both gas and oil occur in the Tilbury field.

The Cayugan strata in the Niagara Peninsula and to the north dip westerly beneath Middle Devonian strata which farther west are succeeded by Upper Devonian beds. The main producing oil horizons of Ontario occur in the Middle Devonian Onondaga and Delaware limestones, and in most fields the production has come from depths of 300 to 500 ft. In every field the oil accumulation is directly related to a dome or a simple type of anticline. These minor features are superimposed on a broad, shallow, basin-like structure.

The Turner Valley field (Fig. 2) in the foothills of Alberta is at present the largest producing field in Canada. The major part of its production is high-grade naphtha occurring with large volumes of gas in the upper 300 ft. of a group of Palaeozoic limestones. Marine Jurassic sediments rest on the eroded surface of the Palaeozoic beds. There are no Triassic, Permian, or late Pennsylvanian beds.

One producing horizon occurs in the Jurassic strata and three in the overlying non-marine Lower Cretaceous beds, but none of these horizons has afforded a persistent or uniform production. It is generally admitted that the Jurassic marine beds may be a source of oil and that little, if any, oil originated in the Lower Cretaceous strata of this area. The lowest producing horizon in the Lower Cretaceous is the Dalhousie sand at the base of the Blairmore formation which in most places in Turner Valley rests directly on Jurassic beds, although in a few places 100 ft. or less of Kootenay coal-bearing strata intervene. It is believed, therefore, that the oil found in the Dalhousie sand was derived from a Jurassic source and migrated upwards. The Home sand also in the Blairmore formation, 250 ft. above the base, is productive in certain areas of Turner Valley. The source of this oil is problematical, but owing to the great amount of faulting and fracturing of the rocks migration presumably could have taken place from lower horizons. The uppermost productive horizon, the McDougall-Segur sand, yields oil only in an area where faulting is known. Since this sand is free of water and is connected by fractures to a known source in overlying marine shales of Colorado age, it is believed that in this case the oil migration has been downwards.

In the Turner Valley field the harder, more competent rocks such as the Palaeozoic limestones and to a less extent the Blairmore strata are apparently much more shattered than the overlying shales which yielded by folding and crumpling. The forces of deformation within the foothills were very intense and not only folded the strata but caused great low-angle overthrust faults, one of which underlies Turner Valley and has a displacement measured in thousands of feet. Subsidiary faults to this low-angle overthrust also cut the strata and cause large repetitions in drilling. On the surface Turner Valley appears to be nothing more than a faulted anticlinal structure, but at depth it is apparent from drilling that westerly dips predominate and particularly on the east flank overturned beds occur. This is due to the fact that the east side is cut off by the major low-angle overthrust underlying the whole structure.

On the plains the Skiff field alone has yielded oil from marine Jurassic beds that underlie southern Alberta and Saskatchewan. The origin of the oil found in this and all other fields in southern Alberta is most easily explained if it be granted that the oil originated in the Jurassic sediments and now occurs either in these beds or in strata contiguous to them. The producing horizon in the Red Coulee field, for example, is near the base of the non-marine, Lower Cretaceous beds in which the oil could hardly have originated. The oil could have migrated, however, from the underlying Jurassic beds. Although no sustained production of oil has been obtained in the Canadian plains from the Palaeozoic limestone underlying the Jurassic, there have been excellent shows in a few wells and production occurs in the Kevin-Sunburst field of Montana. Weathering of the limestone surface in the period following Mississippian and preceding Jurassic time may have produced the porosity necessary for an oil reservoir, and the oil entering this reservoir rock may have had a Jurassic source. If this is so, it follows that the distribution of marine Jurassic beds is the factor controlling the prospective oil territory, and since Jurassic strata possibly do not occur

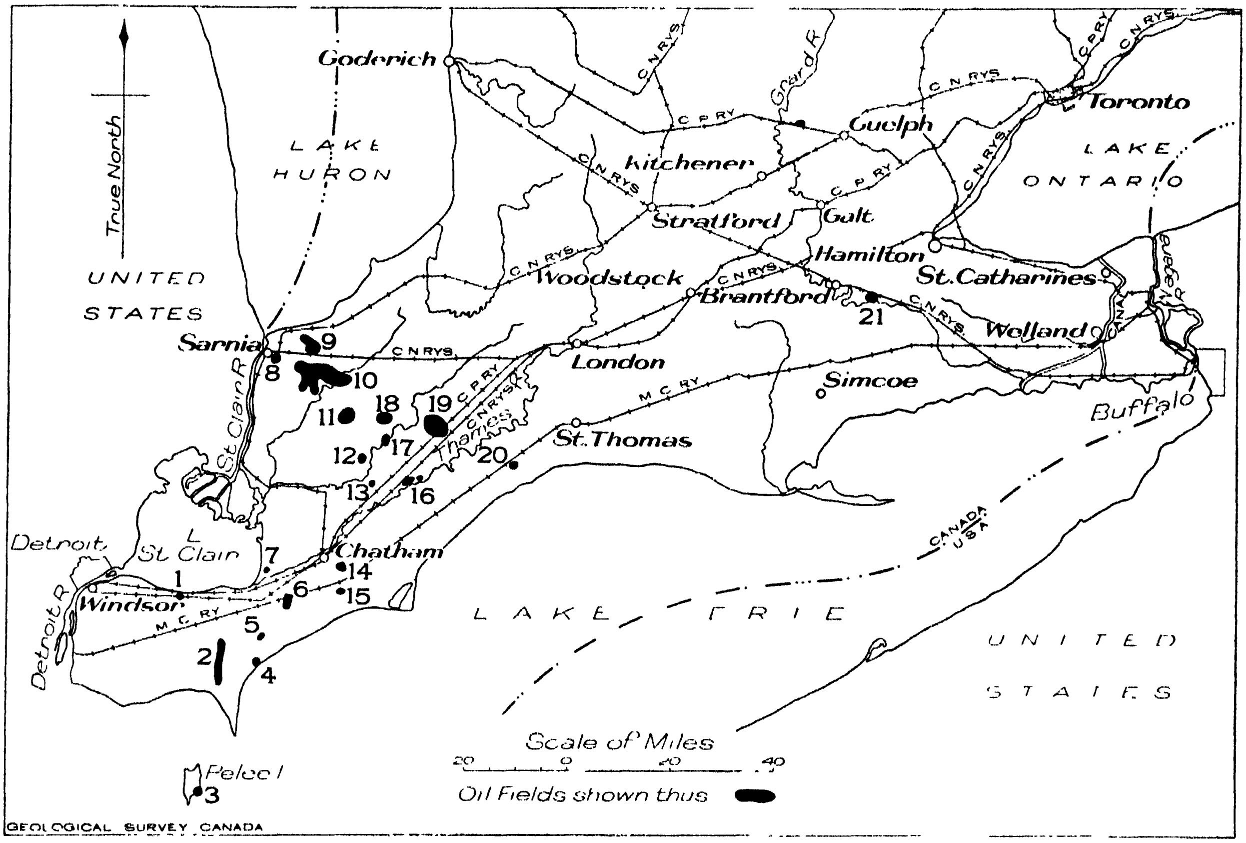

FIG. 1. Index map of south-western Ontario showing oilfields. 1, Belle River; 2, Leamington; 3, Pelee Island; 4, Wheatley; 5, Romney; 6, Tilbury; 7, Dover; 8, Sarnia; 9, Plympton; 10, Petrolia; 11, Oil Springs; 12, Dawn; 13, Thamesville and Tilbury; 14, Kipp; 15, Raleigh; 16, Bothwell; 17, Euphemia; 18, Brooks; 19, Mosa; 20, Dutton; 21, Onondaga.

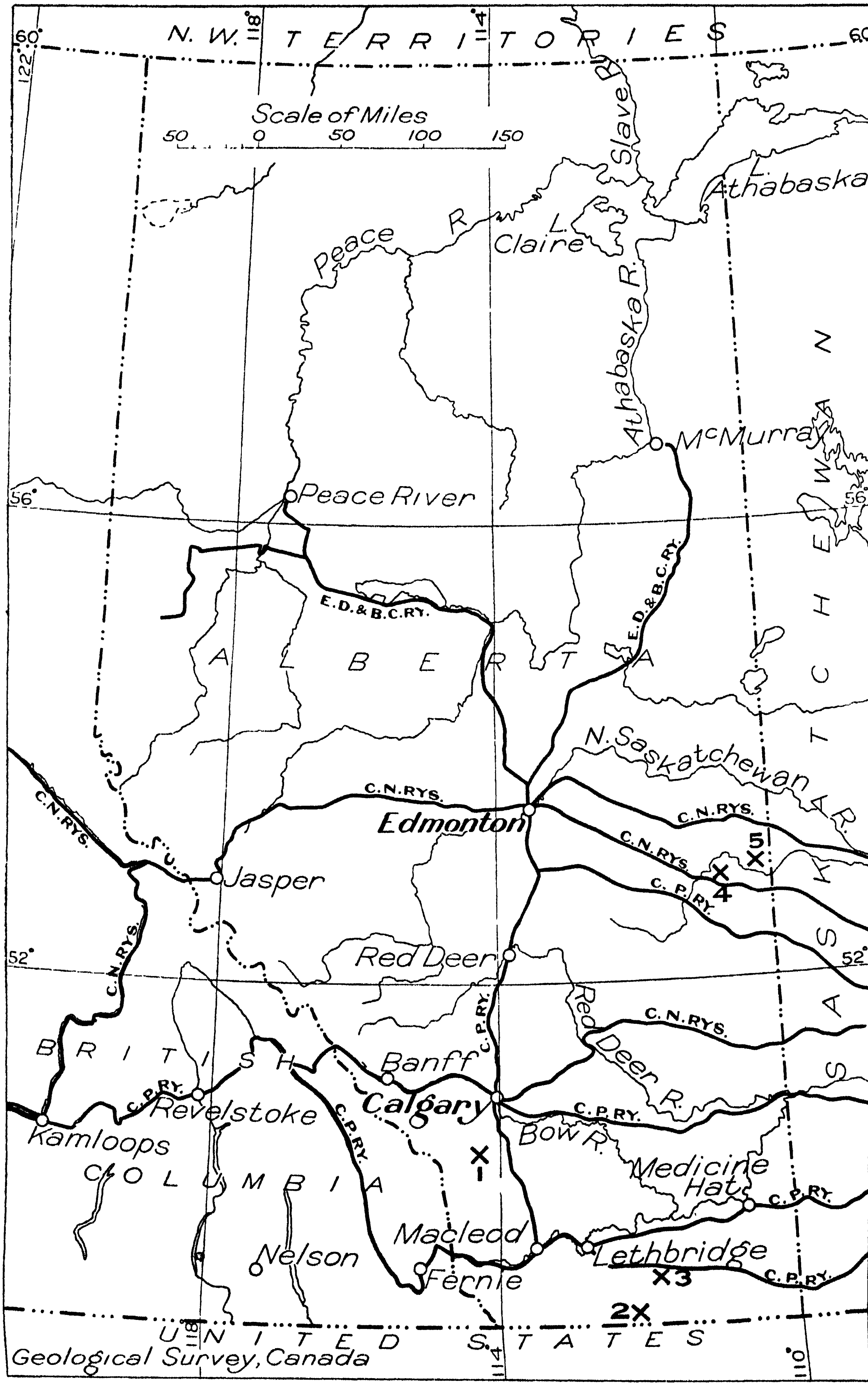

FIG. 2. Index map of Alberta showing position of oilfields. 1, Turner Valley; 2, Red Coulee; 3, Skiff; 4, Wainwright; 5, Ribstone.

more than 150 miles north of the International Boundary in the plains of Alberta and Saskatchewan no oil of Jurassic origin may be expected in the plains north of this limit. Both the Skiff and Red Coulee fields are on anticlinal structures projecting northward from the Sweetgrass arch uplift, the main part of which is in Montana. Gasfields of large capacity also occur on this uplift, and they too are related to local folds.

In the north on Athabaska River, both marine and non-marine Lower Cretaceous strata occur. Southward the marine beds decrease and the non-marine sediments become more and more predominant until in the south-western plains only non-marine beds occur. The edges of the marine formations, representing the shore-lines of former Lower Cretaceous seas, extend south-easterly across north central Alberta to south-western Saskatchewan. These shore-lines with their offshore marine deposits are believed to provide not only good reservoir rocks but abundant source materials for petroleum, and hence it is considered that the oil of the Wainwright field and of the now abandoned Ribstone field and the bitumen in the McMurray ('Tar Sands') formation on Athabaska River had their origin in Lower Cretaceous strata. A number of small folds on a major fold that culminates near the Alberta-Saskatchewan boundary in eastern central Alberta are thought to be directly responsible for the accumulations of oil and gas in this area.

In the Mackenzie River area north of Fort Norman two wells supply oil to mining companies operating on Great Bear Lake. The wells are on the east flank of a basin structure that is bounded by mountains on either side and underlies Mackenzie River valley, here about 20 miles wide. The wells were drilled in westerly dipping beds near an oil seepage and production was secured in Upper Devonian shales. There is no easterly closure, and a short distance east of the wells the truncated edges of the producing beds are exposed. The oil encountered in the wells is probably contained in fracture zones in the shales. Several cross-folds eroded below Upper Devonian beds are known within the basin, and it is probable other less deeply eroded folds exist, although for a number of reasons their location is difficult to determine. The features of this area related to oil prospects are: (1) numerous seepages of oil where the bevelled edges of the Upper Devonian beds are exposed; (2) the presence of Upper Devonian sandstones suited to act as reservoir rocks; (3) the occurrence of marine Cretaceous shale lying on the Devonian beds over most of the basin structure and forming adequate cover to retain the oil; (4) the existence of several cross-folds in the basin structure and the probable occurrence of other less deeply eroded folds. Thus, although the present wells may not yield any large amounts of petroleum, the prospects within the Mackenzie area appear to be excellent on favourably located structures.

[1] Published by permission of the Director, Bureau of Economic Geology, Dept. of Mines, Ottawa, Ontario, Canada.

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GEOLOGY OF THE TÁMPICO-TÚXPAN OILFIELD REGION[1]

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THE oilfields of the Tampico Embayment lie from 20 to 70 km. inland from the Gulf of Mexico between north latitudes 20° 30′ and 22° 30′. There are three fields of major importance, namely:

(1) The Northern Fields, including Pánuco, Topila, Ebano, Cacalilao, Corcovado, Chijol, Altamira, and other sectors. This group lies west of Tampico. The productive area is spotted and irregular in outline. Its greatest width from Ebano in the west to Quebracha in the east is about 50 km. Its north–south extension from Altamira (Los Esteros) to Chijoles (Pánuco area) is about 60 km. (see Fig. 1). Profitable production was found at Ebano in 1904 and at Pánuco and Topila in 1910–11.

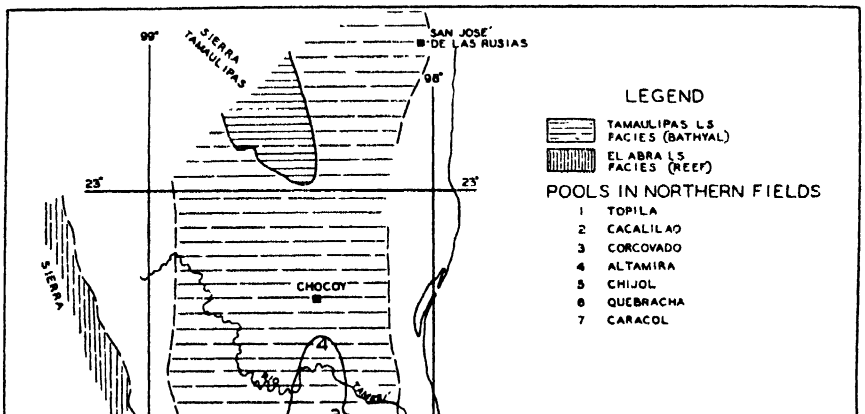

FIG. 1. Map showing location of oilfields and approximate known surface and subsurface distribution of El Abra and Tamaulipas limestone facies.
(*Courtesy of the American Association of Petroleum Geologists.*)

(2) The Southern Fields (Golden Lane) consist of the following divisions from north to south: Dos Bocas, San Gerónimo, Tepetate, Juan Casiano, northern Amatlán (Los Naranjos), southern Amatlán, Zacamixtle, Totcco, Cerro Azul, Potrero del Llano, Cerro Viejo, Tierra Blanca, Chapapote Nuñez, Alamo, Jardín, Paso Real, and San Isidro. The South Fields Ridge forms an arc convex to the west (see Fig. 1). It averages about 1,000 metres in width and has a total length of about 82 km. Excluding the Dos Bocas well [24, 1909] (San Diego No. 3), which was a total loss by fire in July–August 1908, commercial development of the field dates from the latter part of 1910.

(3) The Poza Rica Field is a development of the last few years dating subsequent to the discovery of oil in Mecatepec at the end of 1928. The field lies roughly 50 km. south of Túxpan.

Several small fields of relatively little importance occur such as Furbero, Tierra Amarilla, and Tanhuijo, besides a few other areas where small production has been found.

Stratigraphy

The succession found in wells in the Northern Fields is shown in Table I, and in the Southern Fields in Table II.

Jurassic

Rocks of Kimmeridgian and Portlandian age have been found in wells at Altamira, Chocoy, and Pánuco in the Northern Fields. Several outcrop localities in the Sierra Madre Oriental are referred to by Burckhardt [5, 1930]. He describes the Kimmeridgian and the Lower and Middle Portlandian bituminous shales and the Upper Portlandian limestones, referring to three wells in the Northern Fields. This is also referred to by Baker [2, 1928] and by the writer [15, 1934].

Cretaceous

Lower Cretaceous: Neocomian.

Lower Tamaulipas Limestone. Beds representing the Berriasian, Valanginian, Hauterivian, and Barremian stages are present in the wells that have been drilled to the Jurassic. They are not recorded in outcrop within the limits of the area discussed, except perhaps south-west of Tamazunchale (Fig. 1). As found in wells, rocks of these stages consist of compact grey or white limestones. *Acanthodiscus* aff. *octagonus* Uhlig was identified by Burckhardt from the Berriasian in the Chocoy well.

Beds representing the Aptian are present in wells in the Northern Fields in the form of white limestones, slightly chalky, rarely carrying a little chert.

TABLE I

Succession in Pánuco District

(Range of oil production is shown by heavy vertical line.)

		(*Note*: Eocene and Oligocene beds are present in Topila and Quebracha)
	Palaeocene? or Danian?	*Tamesi* shales 900 ft.+
		unconformity
UPPER CRETACEOUS	Maestrichtian	
	Campanian	*Méndez* shales
	Upper Santonian	800–1,000 ft.
	Lower Santonian	
	Coniacian	*San Felipe* limestones and shales 300–500 ft.
	Turonian	*Agua Nueva* limestones and bituminous shales 260–400 ft. *Inoceramus hercynicus*
MIDDLE CRETACEOUS	Cenomanian	Tamaulipas limestone, upper: White and grey dense cherty limestones 480–600 ft.
	Albian	Black shale at base. 20 ft.
LOWER CRETACEOUS	(Aptian)	Tamaulipas limestone, lower: White and light grey cherty limestone 1,000 ft.
	Neocomian	*Acanthodiscus* aff. *octagonus* Uhlig
		Probable hiatus
UPPER JURASSIC	Upper Portlandian	Limestones
	Lower and Middle Portlandian	Limestones and carbonaceous shales
	Kimmeridgian	Bituminous shales

TABLE II

Succession in Southern Fields

Middle Oligocene	*Mesón* Sandy limestones and sandy shales
Lower Oligocene	*Huasteca* Grey shales with some thin sandstones (overlaps El Abra at Dos [illegible]) *unconformity*
Upper Eocene	*Chapapote* Grey shales (surface rock from Chapapote Nuñez to Toteco)
Middle Eocene	*Tempoal* Brownish shales (thinly represented north of Toteco)
Lower Eocene	*Aagón* shales *unconformity*
Palaeocene? or Danian?	*Tamesi* (Probably represents phase of Upper Chicontepec) Grey and red shales *unconformity*
Upper Cretaceous	Upper *San Felipe*-lower *Méndez* *unconformity*
Middle Cretaceous	*El Abra* limestone (upper Cenomanian missing) *Pecten roemeri* Hill at top *Orbitolina texana* Roemer (zone fossil of facies of Glen Rose of Texas) found 7,100 ft. below top of El Abra limestone in well at Jardin, south-east of Alamo

The foregoing series of limestones is designated the Lower Tamaulipas limestone. The facies is called bathyal by Burckhardt [5, 1930].

Middle Cretaceous: Albian-Cenomanian.

Upper Tamaulipas Limestone. Grey cherty limestones (bathyal facies) of this age crop out in the Sierra Madre south-east of Tamazunchale. These beds take their name from the Sierra Tamaulipas (Fig. 1). The type locality of the Upper Tamaulipas limestone lies in the Borrega Cañon on the west side of the Sierra Tamaulipas. Flaggy and massive bedded grey and white cherty limestones are exposed, the lowest part, consisting of black limestones and shales, belonging to the base of the Albian. In wells in the Northern Fields the beds consist of grey and white dense cherty limestones. Oil production has been found from the base upwards. The total thickness of the Tamaulipas limestone (Lower and Upper) in the Northern Fields is about 1,600 ft.

El Abra Limestone. Albian and Lower Cenomanian rocks in a reef facies crop out in the Sierra Madre west of Tampico. This facies is named El Abra limestone. The top of the El Abra is equivalent to the Buda of Texas. It is a porous or cavernous, predominantly light-grey limestone built up of the remains of miliolids, rudistids, and shelly debris. Albertite is found in fossil cavities. The highest beds consist of black bituminous limestone near El Abra, the type locality (Fig. 1). El Abra limestone forms the reservoir rock in the Southern Fields (Golden Lane). It has been referred to, erroneously, as the 'Tamasopo limestone'. The Tamasopo Cañon limestone is of younger age, Coniacian (Austin Chalk), and possibly includes part of the Turonian in its lower part and the Santonian in the upper part. Except that the Upper Cenomanian is missing, the type El Abra is the time equivalent of the Upper Tamaulipas limestone. The approximate distribution of the two facies is shown in Fig. 1. A mixed type of facies, or merging of the Tamaulipas and El Abra limestones, forms the reservoir rock in the Poza Rica Field.

Upper Cretaceous: Turonian.

Agua Nueva Formation. Overlying the Tamaulipas limestone is the Agua Nueva formation [see 15, 1934] a series of black and dark-grey chert-bearing limestones with bituminous black shales containing *Inoceramus hercynicus* Petraschek and *I. labiatus* Schlotheim. These beds are characteristically recognizable both in outcrops and wells, though the colour of the limestones may be predominantly light grey in some areas (Pánuco Field) and the amount of interbedded black shale vary in the different levels in one area as compared with another. The thickness in the Pánuco area is from 260 to 400 ft. Production is found from top to bottom of the formation in the Northern Fields. It is absent in the South Fields, though it has been found in wells some kilometres east, or west, of the structure. It is present in wells in Pozo Rica.

The Agua Nueva is generally thicker in synclines than on tops of anticlines. No hiatus is present above the Tamaulipas limestone.

Coniacian and Lower Santonian.

San Felipe Formation. Overlying the Agua Nueva is a series of alternating greenish-grey, grey, and white limestones, and grey shales. Limestones are more predominant in the lower part and shales in the upper part. These beds are named the San Felipe formation [15, 1934] and are approximately equivalent to the Austin Chalk of Texas. The type locality lies west of San Felipe station on the Tampico–San Luis Potosí Railway. The San Felipe contains facies changes; in a few places it is entirely an argillaceous deposit, in others mainly calcareous. Its thickness in the Pánuco area may vary from 300 to 400 ft. Production is only found in the basal 80 ft., except in a few anomalous cases where it is encountered higher up.

A thin development of the uppermost San Felipe, not exceeding about 50 ft. in thickness, is present with overlap on El Abra limestone in the South Fields Ridge.

Upper Santonian, Campanian, and Maestrichtian.

Méndez Formation. Grading up from the San Felipe is a series of grey foraminiferal shales known as the Méndez formation. The upper part (about 40–100 ft. thick) consists of pinkish to purplish-red shales.

The Upper Méndez can be correlated with the beds near Cárdenas, State of San Luis Potosí. The Cárdenas beds are of Maestrichtian age. Hitherto the Méndez has been considered as Santonian-Campanian only and equivalent to the Taylor marl of Texas, but the Navarro is represented by the Upper Méndez; see Adkins [1, 1932]. The name Papagayos was used by Dumble [14, 1918]. It should be regarded as a group name representing an argillaceous facies of all the San Felipe and the Méndez.

The Méndez crops out in Chocoy, and extends southwards to Cacalilao. Its type locality lies 300 metres east of Méndez station on the Tampico–San Luis Potosí Railway. The Méndez has a thickness of 800–1,100 ft. in the Northern Fields. In the South Fields Ridge only a thin remnant is present.

Distribution of Cretaceous Rocks

The Tamaulipas, El Abra, Agua Nueva, and San Felipe are only found cropping out in the areas of the Sierra Madre and Sierra Tamaulipas. Elsewhere in the Tampico Embayment they are covered by younger rocks. The Méndez is found in the inter-montane valleys and on the east side of the Sierra Madre Oriental and on both flanks and the south plunging end of the Sierra Tamaulipas. South of the Río Pánuco the Méndez is covered by younger beds.

Uppermost Cretaceous or Palaeocene?

Tamesí Formation. Unconformably overlying the Méndez is a series of grey and red shales named the Tamesí formation by Belt [3, 1925]. There is a distinct palaeontological break between the two formations and a hiatus is present. The Tamesí is found overlying the Méndez on both flanks of the Sierra Tamaulipas. It crops out in the Río Pánuco near the town of the same name. It forms the surface rock in the Ebano Field and in the extreme eastern and western parts of Cacalilao. About 900 ft. of the formation have been drilled through in some wells. In the Southern Fields it is present with a thickness up to 400 ft. It is lacking on some parts of the ridge. No macro-fossils have yet been found in the Tamesí, and a statement as to age on the basis of the micro-fauna is still a matter of uncertainty. The Tamesí can be regarded as post-Maestrichtian and of earlier age than the equivalent of the Midway (Lower Eocene) of the Gulf Coast.

Tertiary

Lower Eocene.

Chicontepec Group. The name Chicontepec was referred to by Dumble [14, 1918] in describing a series of sandstones

and dark shales near the town of the same name. Around Tanlajás the part of the Chicontepec exposed is of Upper Midway age. The Wilcox (of the Gulf Coast) is probably represented elsewhere in the Chicontepec group. From Tancanhuitz south-eastwards the Chicontepec forms the foot-hills of the Sierra Madre. It is a shallow water and, in part, deltaic deposit. It is not found (*sensu stricto*) in the wells of the Northern or Southern Fields.

Aragón Formation. The Aragón shales are described by Nuttall [17, 1930]; they overlie the Chicontepec. The Aragón crops out in a few areas about 50 to 70 km. west of Túxpan and south-east of Aldama north of Tampico. It is found in wells in the Southern Fields and near Topila. Its average thickness is about 500 ft. The Aragón probably represents uppermost Midway or Wilcox of the Gulf Coast.

Middle Eocene.

Tempoal Formation. Overlying the Aragón are shales described as Tempoal formation by Ver Wiebe [23, 1924] and Belt [3, 1925]. The type locality is at the town of Tempoal. Cole [6, 1927] later used the name Guayabal for these beds. The shales are chocolate-coloured and contain ironstone nodules. A total thickness of at least 1,600 ft. is developed. The Tempoal is present in the South Fields Ridge. The Tempoal is of Claiborne age and the upper part can be correlated with the Cook Mountain of the Gulf Coast.

Upper Eocene.

Chapapote Formation. The name Chapapote formation was introduced by Cole [7, 1928]. The Chapapote shales are a deeper water deposit representing beds of nearer shore facies described as the Tantoyuca formation by Ver Wiebe [23, 1924] and Belt [3, 1925]. The Chapapote (and Tantoyuco facies) is regarded as equivalent in age to the Jackson of the Gulf Coast. It has a total thickness in excess of 1,300 ft. It is found in wells at Topila and on the South Fields Ridge.

Lower Oligocene.

Huasteca Formation. Shales of Lower Oligocene age were referred to as Alazán by Vaughan [22, 1924] and Cooke [8, 1928]. The Alazán had previously been defined as Eocene by Dumble [14, 1918].

Various authors have referred the shales in the Río Buenavista near Alazán to the Eocene, and others have referred them to the Oligocene. Beds of *both* ages occur at the locality, with overlap of the Byram marl equivalent on the Jackson. Eocene inclusions (with micro-fauna) occur in the Oligocene. Confusion is here avoided by adoption of the name Huasteca.

The Huasteca formation consisting of grey sandy clays and thin sandstones is typically exposed at Paso Comales on the road between Ozuluama and Tantoyuca. It is present at Topila and in the Southern Fields area in a deeper water facies than at Comales. The Huasteca is the equivalent of the 'Alazán' in the sense used by Cooke [8, 1928] and Nuttall [18, 1932]. The Huasteca is found in wells in the Southern Fields with a thickness up to 2,000 ft. or more.

Middle Oligocene.

Mesón Formation. Conformably overlying the Huasteca is the Mesón. The name Mesón formation was introduced by Dumble [14, 1918]. The Mesón consists of shales, sandy limestones, orbitoidal and coralline limestones. It forms a belt near the coast up to a width of about 20 km. in places. It has a thickness of more than 1,000 ft., perhaps twice that amount in some areas. In places it overlaps the Chapapote and even on to the Aragón. It is found in wells in Topila and on the South Fields Ridge. The upper part of the Mesón has been referred to as San Rafael.

Miocene

Túxpan Formation. Named by Dumble [14, 1918] from its occurrence at the town of Túxpan. It consists of beds of sandstone and sandy limestone with beds of grey shale. Its age is regarded as Lower Miocene. It overlaps the Mesón. Its occurrence is confined to a narrow strip along the coast, but in the neighbourhood of Papantla it is better developed, both in a surfacial way and as regards thickness.

Pleistocene and Recent

Beds of Pleistocene age occur in the lagoons near Tampico and are found overlying the Oligocene in places farther inland. Alluvial tracts are developed in the valleys of the Pánuco, Tamesí, and other rivers.

Igneous Rocks

Andesitic and basaltic plugs and dykes of post-Oligocene age occur frequently throughout the Southern Oilfields and in the territory between the coast and the Sierra Madre. With two exceptions intrusions in the Northern Fields are limited to the Ebano area. Diorite and gabbro are not found on the surface, but have been encountered in wells at depth in the Northern and Southern Fields and in Aguada. Syenitic rocks are intruded in the Sierra Tamaulipas. Extrusive rocks occur near Aldama (north of Tampico) and at other places.

Seepages

Asphaltic seepages (*ojos de chapopote*) occur in the Southern Fields area, and in the Ebano district. Almost invariably they are connected with igneous intrusions, plugs, or dykes, the oil having worked its way upwards along the contact of the igneous with the sedimentary rocks. The subject is fully discussed by De Golyer [12, 1915; 13, 1932].

In a few places in the Northern Fields, western Cacalilao, Garrucho, and Altamira (Los Esteros), the seepages are associated with faulting and not with intrusions.

Structural Conditions in the Oilfields

As distinct from the folding of the Sierra Madre Oriental, the Cretaceous limestones of which are often overfolded or consist of fan-shaped folds, the oilfields lie in a structural belt in which the folds can be regarded as deep seated in origin. This difference in the tectonics is referred to by Böse [4, 1927] and Staub [20, 1931].

Northern Fields. The Northern Fields, Pánuco, Ebano, Topila, &c., lie on the plunging prolongation of the Sierra Tamaulipas anticline and should be regarded as part of that large structure (see Fig. 1). South of the Tampico–San Luis Potosí Railway a dominant feature of the area is the presence of north-east trending cross-anticlines. The Ebano Field, eastern Cacalilao (Fig. 2), the southern part of Pánuco, and the Quebracha Field are situated on north-east or north-north-east trending structures, though the regional structural trend is about north 15° to 18° west. Normal faults of both north-east and north-west directions occur, besides some with a nearly north–south trend. The

faults are usually of small displacement, having a throw of 30 to 60 ft., but occasionally about 100 ft. Step faulting with a total downthrow of 360 ft. occurs in the south-east part of Cacalilao. Reverse faults occur very rarely. Production has been found at depths of 1,400–2,500 ft. below sea-level, ranging from the basal San Felipe (restricted sense) to about 600 ft. below the top of the Tamaulipas limestone.

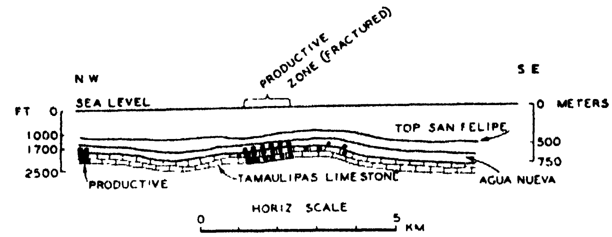

FIG. 2. Cross-section through eastern Cacalilao anticline. (Note. Relative richness of production shown by black dots.)

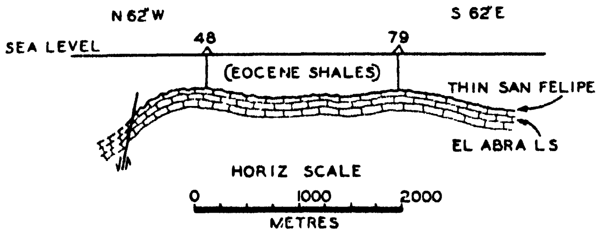

FIG. 3. Cross-section through north part of Cerro Azul.
(*Courtesy of the American Association of Petroleum Geologists.*)

Southern Fields. The South Fields Ridge is regarded as an asymmetric anticline (Fig. 3), frequently cross-faulted, though it is referred to by some as consisting of a downthrown fault [19, 1926] feature on its west flank. From Dos Bocas to Toteco the folds have a north-east or north-north-east axial trend. A change of trend occurs at Cerro Azul-Toteco, the crest maximum of the ridge. South of Potrero del Llano, from Cerro Viejo to Alamo and San Isidro the trend of folding is south-east or parallel to the Sierra Madre Oriental. The Dos Bocas–Alamo structure was subject to oscillation in level during Albian to Santonian time. During the Eocene and Oligocene it was subjected to differential movements as evidenced by the various unconformities. Production in the El Abra limestone is found at depths of 1,200 to 2,300 ft. below sea-level. The Southern Fields Ridge is covered by Tertiary beds of various stages which do not reflect the underlying structure.

Poza Rica. The Poza Rica Field, lying in the synclinal area between the Sierra Madre and the southern end of the 'Golden Lane', consists of a broad, gently folded structure. Production is found in limestone of Cenomanian age (mixed facies of Tamaulipas and El Abra) at depths around 7,200 ft. below sea-level.

Furbero Field. Oil accumulation in this field occurs in metamorphosed Eocene shales at the contact with an igneous intrusive (gabbro). The field is described by De Golyer [11, 1915–16].

Porosity in the Limestone Reservoir Rocks [15, 1934].

Northern Fields. Porosity in the dense limestones of the Tamaulipas, Agua Nueva, and basal San Felipe beds is due to fracturing of the rocks or opening of joint planes. Fracturing is associated with faults of small displacement. In some places the rocks have been shattered. In some areas good production is found on the crests of anticlines, and in others the more prolific production occurs on the flanks (see Fig. 2). The three formations mentioned form a single physical unit as regards accumulation and production of oil, communication (vertical permeability) occurring through the highly inclined fissures and joints. No dolomitization of the limestones occurs, only a trace of magnesium carbonate being found.

Southern Fields. Porosity in El Abra limestone is mainly due to fossils existing as hollow casts. Additional porosity is present due to faulting, solution enlarging the fissures. The latter features have favourably affected the permeability of the limestones, and assisted long-range drainage of the structures by single wells over distances of several kilometres; production from three wells alone is about equal to one-quarter of the total production from the entire ridge. El Abra is practically pure limestone, the proportion of calcium carbonate amounting to about 97%.

Nature of the Oil and Gas

Northern Fields. The gravity of the asphaltic oil is 12·5° A.P.I. in Pánuco, Cacalilao, and Corcovado. Eastward towards Topila the oil gradually becomes lighter, the gravity A.P.I. being from 14 to 15°. In the vicinity of Ebano oil of 11° gravity A.P.I. is found.

Gas throughout Cacalilao, Corcovado, Ebano, and Altamira is inflammable, containing about 40 to 52% methane and from 48 to 57% carbon dioxide. In Pánuco and Topila the gas is non-inflammable (except in a few rare cases), the proportion of carbon dioxide amounting to 85 or 90%. The gas in the Quebracha Field contains from 95 to 97·9% carbon dioxide.

Southern Fields. The gravity A.P.I. averages from 19 to 22°. In San Gerónimo it is 15° A.P.I. and in the Tierra Blanca pool 24° A.P.I. In Poza Rica the gravity A.P.I. is 28°. At Furbero it is 24° A.P.I.

Gas in the Southern Fields is everywhere inflammable, the amount of carbon dioxide present varying from 10·7 to 18·1%.

Analyses of gases from the Northern and Southern Fields are quoted by the writer [16, 1935].

Production

The following figures refer to the total production up to and including 31 December 1934:

Northern Fields (Pánuco, &c.)	705,800,000 bbl.
Southern Fields (Golden Lane)	986,000,000 „
Poza Rica (and Mecatepec)	5,400,000 „
Furbero	2,180,000 „
Miscellaneous Pools	2,000,000 „ .

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MAPS

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EASTERN VENEZUELA AND TRINIDAD

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THE oilfields of eastern Venezuela lie mainly in the State of Monagas, on the flat Llanos plains of the Orinoco opposite Trinidad. Exploratory drilling is now extending westwards into the State of Anzoategui, but these areas are as yet insufficiently developed to be regarded as proved territory. On the island of Trinidad all the proved oilfields lie in the southern half and appear to belong to the same geological province as Monagas and Delta Amacuro. The main areas of production and some of the exploratory wells in Monagas and Anzoategui are shown on the accompanying map.

Oil production in these territories is largely the result of development during the last two decades. In Trinidad, it is true, development began as early as 1905, but it did not attain appreciable proportions until 1914, from which date the industry has grown steadily in importance and the production is now of the order of 2 million tons per annum. Eastern Venezuela attracted considerable attention in 1913, and some drilling was done near the pitch lake of Guanoco, but the main oil-pool of this region—Quiriquire—is entirely a growth of the last decade.

Trinidad

The general stratigraphy of the Trinidad oilfields is complicated by the occurrence of a number of different facies in the various sectors of the island. The Northern Range is largely composed of slightly metamorphosed Cretaceous or earlier rocks, and these probably represent the oldest series in the area. Most of the rest of the island is formed of Tertiary sediments, but there are exposures of Cretaceous along the axes of the major uplifts, particularly in the Central Range, and the presence of such rocks has been shown by borings and by sedimentary volcanism in the south of the island.

Outcrops of Eocene and Oligocene are confined to the cores of the major uplifts in the Central Range, Naparima area, and the Southern Range. Around these uplifts and in all the intervening territory the successive members of the post-Oligocene formations are seen. The folding is in a general ENE.–WSW. direction, crossing the island from end to end. It is logical to assume that this folding is connected with that which is known in the foot-hills of the mainland north of Maturin. Folding movements appear to have continued until quite recent times, and although it is clear that there were early movements of considerable intensity, it is noteworthy that even the Upper Miocene, and in places the Pliocene, has been extensively disturbed. The last important episode, both in Trinidad and on the mainland, was the deposition of a flat sheet of sands and clays which, in places, has completely covered the underlying folded beds, and attains considerable thicknesses in Venezuela. It is not usually thick in Trinidad.

A synopsis of the general stratigraphy is given in tabular form.

In the main the sedimentary sequence reveals the following phases:

(*a*) A Cretaceous-Eocene period of gradually shallowing water with the formation of limestones, shales, and sandstones.

(*b*) An Eocene-Oligocene period of shallow but clear water conditions with much organic deposits—occasionally foraminiferal marls, limestones, glauconitic sands, &c.

(*c*) An Upper Oligocene-Middle Miocene period of sea invasion with much terrigenous sands and clays in the south, but with clear water reef limestone periods and shallow water marls in the middle and north of the island. Strong folding movements took place during this period.

(*d*) A transformation to brackish- and finally fresh-water conditions in the Upper Miocene-Pliocene, associated with the dying down of the folding movements.

(*e*) A final deposition of the flat terrestrial sediments of the Orinoco delta over parts of the island.

So far as the proved oilfields are concerned the productive rocks are mainly in the Miocene marine development of period (*c*). In Trinidad and Eastern Venezuela there is abundant evidence of oil and gas in the Cretaceous, but no commercial production has been obtained from such rocks, although some of the oil produced from the Miocene may be migrant from the underlying Cretaceous. In the main the oil reservoir rocks are lenticular sands of varying thickness and lateral extent. This has resulted in the development of production not only on the anticlines, but deep into, and even across, the synclinal axes, as in the case of the Siparia syncline. Both folding and faulting are well displayed, and, save for the Palo Seco area, the major fields are dominantly anticlinal.

More than 90% of the oil produced in Trinidad has come from a small area between Brighton and Palo Seco. This comparative concentration may be due to interdigitation of the sandy 'Forest-cruse' facies with the clayey facies of the Naparima region, but there are other possible contributory factors such as the Pt. Fortin-Los Bajos fault, which may have acted as an oil-feeder, and also the proximity of the Central Range with its many dislocations.

The Central Range has not yet been seriously tested except on its southern margin, where a highly disturbed zone has numerous oil indications which have attracted attention. In this zone lies the **Tabaquite** field with its light oils (0·82 sp. gr.). It appears to be on a northerly dipping thrust block composed principally of Nariva sands (Miocene). The oils from these sands are aromatic, but a paraffinic oil is obtained from deeper horizons which may possibly be of Eocene age. The **Brighton** field is a gentle dome of about 1 mile radius, with the famous Pitch Lake on its crest. The uppermost beds belong to the La Brea and Moruga formations which are underlain normally by a rather clayey facies of the Forest and Cruse series. All are highly impregnated with a heavy sulphurous oil, and in earlier days the La Brea beds were exploited. An important unconformity occurs below the Cruse series, which strongly overlaps a highly imbricated Cretaceous-Eocene complex. Apparently the Brighton dome lies on the south-western prolongation of the much-disturbed southern edge of the Central Range.

East-north-east of Brighton, in the highly folded Oligocene-Miocene series of the Oropuche Lagoon and the

Naparima territory, a number of exploratory wells have proved the existence of light oil and gas sands in the Ste Croix formation without revealing any considerable field as yet. The intensity of folding appears to diminish southwards from the Central Range. This may be partly the result of smaller stresses towards the south, but it is also associated with the fact that the beds involved are younger. These conditions arise more especially in the fields which lie well to the south.

The **Vessigny** field is connected with the Vance River important unconformity at the base of the Cruse with considerable overlap on to an old ridge which appears to attain its maximum in the southern syncline. These conditions demonstrate the importance of the pre-Cruse topography, which determined the zones of basinward in-fill and caused rapid changes in thickness of the Cruse horizons against the old landscape. There are many signs that sedimentary volcanism had a strong influence on the distribution of oil and gas, not only in the Parrylands fields, but also in the general region towards Brighton.

	Trinidad			
	North and Central		Southern	Eastern Venezuela
Holocene	Talus, river flat, swamp and beach deposits			
Pleistocene	Gravel terraces Matura formation		Megatherium sand Godineau formation	Llanos formation
Pliocene	Comparo formation		La Brea formation	Quiriquire formation
Upper Miocene	Caroni formation Manzanilla formation	*(Naparima area)* Naparima formation	Moruga formation Forest-Cruse formation	'Mollusc Miocene' of Urica
Middle Miocene	Springvale Mont Serrat Brasso sand Brasso clay	Upper Green clay		
Lower Miocene	Brasso clay Tamana formation	Sphaerodinella clay Ste Croix formation	Palo Seco formation Ste Croix formation	
Oligocene	Alley Creek formation (Lower Green clay) Morne Diablo formation (Bamboo clay)		Alley Creek formation Morne Diablo formation (Cipero clay)	Monagas shales
Upper Eocene	Mount Moriah formation Pointe à Pierre formation		Mount Moriah formation Pointe à Pierre formation	Mount Moriah formation Aragua formation
Middle and Lower Eocene	Dunmore Hill marl		Pelican Rock marl	
Paleocene	Soldado formation Tarouba formation (San Fernando argilline)		Soldado formation Tarouba formation (Lizard Springs shale)	Soldado formation
Cretaceous	Roudairia beds Caprinid limestone La Carrière formation (Laventille limestone) (Patos conglomerate)		La Carrière formation	Guayuta shales El Cantil formation Barranquin formation

anticline which curves round the south and south-east of the Brighton structure. Production has been obtained from the Forest sands, below which the sandy facies of the Cruse is poorly developed. Recently there have been attempts to find oil at deeper horizons, and these have shown a highly sulphurous oil, though not in commercial quantities, in the Amphistegina marls below the unconformity.

Immediately to the south lie the **Parrylands** fields. Attention was first drawn to this area by the outcropping 'Tar sands', which swing round the western plunging end of the Lot-I anticline. These beds are of Lower La Brea age, charged with migrated and inspissated oil. The early production was from Forest sands, but later developments in the underlying Cruse horizons have been much more important. The richest zone is on the southern flank which dips at 16–20° for about 2 miles to the axis of the syncline. Recent developments in the west have disclosed a rich zone on the plunging anticlinal axis, and a broad area of production on the western prolongation of the northern flank towards the Guapo area. All these developments are in Forest and Cruse horizons. Deep drilling has shown an

South of the Parrylands is the **Fyzabad** field, a series of separate domes on the Central anticline. The Forest dome is about 1½ miles long and is followed to the east by the Bernstein dome which is approximately 2 miles along the axis. The Apex field is slightly offset to the south, and occurs on a subsidiary structure on the western plunge of the Santa Cecilia anticline. The latter is a more extensive uplift which stretches towards Debe where the Ste Croix beds are exposed in the core of the fold. North-east of Apex the sandy development of the Forest-Cruse formation gives place to a clayey facies, and the prospects of oil in this area are reduced to the speculative possibilities of the pre-Cruse formations. The crestal region of the Central anticline is considerably broken by epi-anticlinal faulting. Its oil production is very irregular and is much affected by water. The northern syncline is shallow, the oil in this region is heavy and asphaltic, and is also associated with much water.

The southern flanks of this line of domes from Forest to Apex merge into a continuous monocline which extends down to the Siparia syncline, the axis of which is 2–3 miles

from the anticlinal crest. The Forest clay horizon which outcrops on the crest lies 5,000–7,000 ft. deep in the bottom of the syncline, and the flank has an average dip of 30–35°. This is the best zone of oil production in Trinidad. There is a considerable amount of block-faulting on this flank, and it is evident that the faults have played an important role in the migration of oil, gas, and water. The distribution of oil and water is markedly dependent on the fault blocks, and the character of the oil is frequently modified, apparently by having suffered repeated injection along the fault planes.

Very little production is encountered in the Moruga beds overlying the Forest clay, and the early production was derived mainly from four sandy horizons which occur in the 1,200 ft. of Forest beds. Later the deeper Cruse series was exploited. This series thickens towards the syncline where the total thickness is about 1,500 ft., and it contains some five main sandy horizons. Deeper formations have not yet been thoroughly explored.

In the Penal region east of Apex a secondary fold appears on the south flank of the Central anticline. This fold extends into the region of **Barrackpore,** and a small field has been developed on its faulted southern flank. The Cruse horizons there are almost wholly clays, and the oil production is from younger sands which, unfortunately, are partially watered.

Immediately west of the Forest field the Central anticline abuts on an important WNW.–ESE. line of dislocation, which is apparently pivotal in nature. On the western end of this line, and on the northern side, is the **Pt. Fortin** field. It is on a strong fold with its faulted northern flank dipping at 40°, and overthrust to the south. Production is obtained on the crest and the northern flank from the Forest and Cruse horizons. The field stretches about 1½ miles along the crest and is about half a mile wide.

East-south-east along the same line of dislocation the upthrown and downthrown sides are reversed, and the **Los Bajos** field is developed in the Forest and Cruse series on the upthrown southern side.

The **Palo Seco** field occupies the northern slope of the Morne Diablo structure between Erin and the eastern prolongation of the Los Bajos fault. The producing horizons are in the Forest and Cruse series, though recent developments have found oil in the Palo Seco beds below the Cruse. All the producing beds outcrop immediately to the south, and although it is true that many of the sand bodies are water-bearing, yet some carry oil, and it is remarkable that oil should be preserved under such conditions. Their productivity must be the result of lenticularity coupled, perhaps, with the sealing effects of minor faulting and asphaltization.

In the south-east of the island the Siparia-Ortoire syncline is bounded on the south by an important uplift in the Lizard Springs area. The core of this uplift consists of Cretaceous, Eocene, Oligocene, and Lower Miocene shales which were deeply eroded before the deposition of the Cruse and Forest series. A sandstone development, over 6,000 ft. thick, of Moruga and younger formations covered the entire southern area, and subsequent movements folded and fractured the rigid sandstones overlying the incompetent shales. Considerable differential thrusting and slumping was thus produced, and remarkable transformational movement of oil and gas has given some of the most outstanding examples of sedimentary volcanism in the island. The oil has impregnated broad areas of the basal Moruga series, and has been trapped on the flanks of the uplifts by strike-faulting and unconformity. Two areas of production have been developed, the most important of which lies on the faulted plunging end of an uplift at **Guayaguayre.** The oil in this region is generally asphaltic, but there are some occurrences of a lighter paraffinous oil.

Recent developments in Trinidad include an intensive programme of exploratory wells which are situated principally on the northern flank of the Central Range, the Cedros Peninsula, the Coora-Morne Diablo-Herrera segment of the Southern anticline, the Penal area, and at Rio Claro.

Eastern Venezuela

The present area of development at Quiriquire, and especially the regions of exploratory drilling, are covered by the Llanos formation—a thick blanket of Pleistocene and Recent deposits. Exposures of older rocks are seen only in the extreme north and south. In the north the hills of the Caribbean Range project through this blanket of Llanos and show, in the main, well-folded Cretaceous and Eocene beds with a strip of folded Miocene on the edge of the foot-hills. In the south the first exposures of the basement rocks are only seen along the banks of the Orinoco. These consist of metamorphic schists, quartzites, and plutonic rocks, and are covered immediately to the north by a blanket of Llanos deposits which thickens northwards as the basement gradually plunges in that direction. Our knowledge of this region is based entirely on the results of geophysical work and of a few exploratory wells. It appears that the basement plunges northwards in a series of undulating slopes and terraces, and that successive members of the Miocene are overlapped southwards by the gently dipping Pliocene and Recent deposits. The northerly plunge continues for about 60 miles to a deep basin south of Maturin, and it is only in this general region that true folding can at present be substantiated.

The geological sequence is not so well known as in Trinidad for the Oligocene and younger formations, and the tentative classification shown in the Table is suggested.

The main episodes in the geological history of this area are as follows:

(*a*) The deposition of an extensive Cretaceous series of grits, limestones, and shales, followed by thick sandstones of Eocene age.

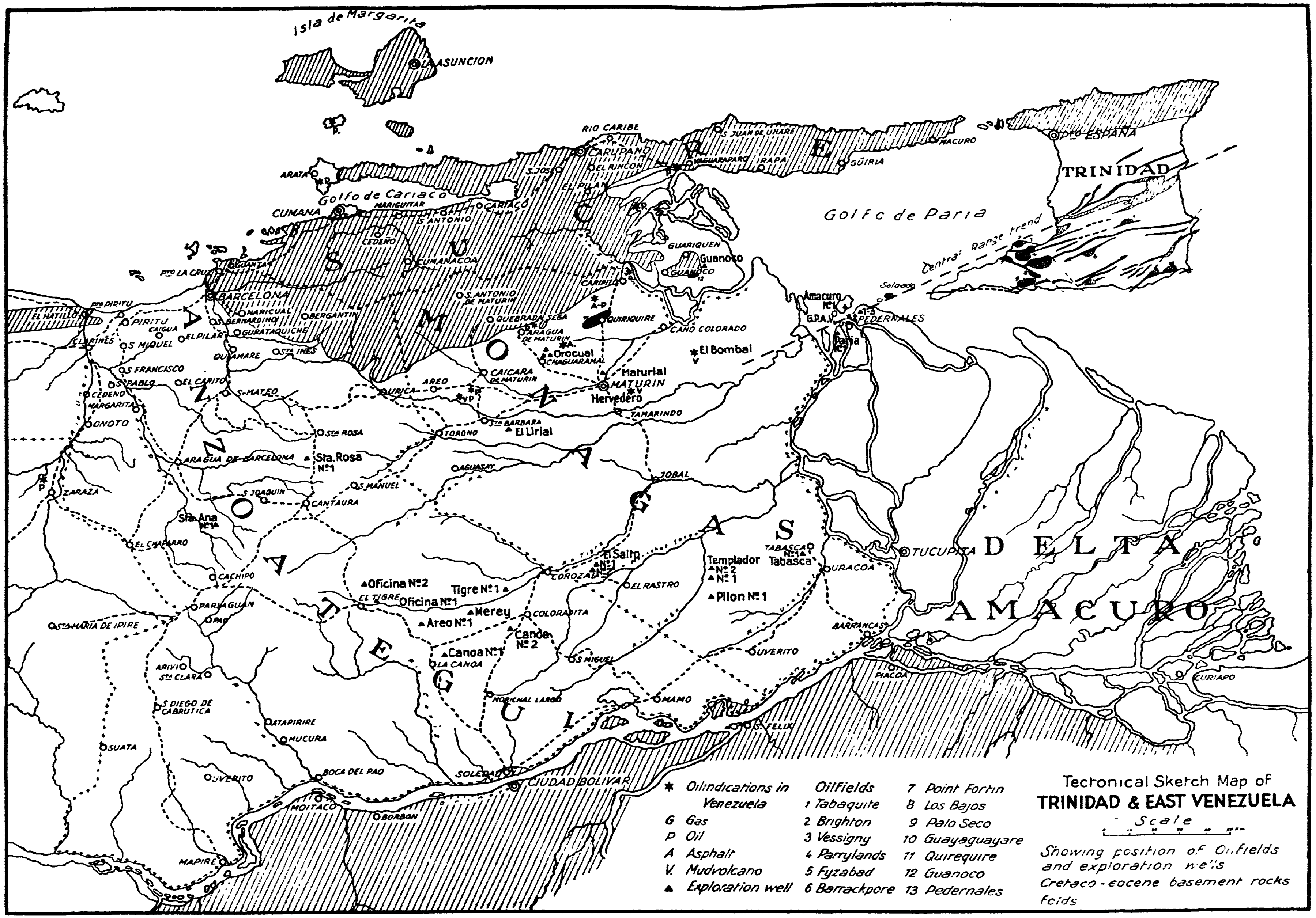
(*b*) A possible but not fully proved episode of clear shallow water of Upper Eocene-Lower Oligocene age.

(*c*) Extensive but gradual depression of the main basins with depositional overlap of the Upper Oligocene and Miocene. It is probable that a considerable folding movement separated stages (*b*) and (*c*) in the north.

(*d*) The later stages of in-filling were associated with a more sandy facies with extensive subsidence in the north and the formation of thick masses of sandstone and shales, followed by folding movements in the northern area.

(*e*) The whole basin was covered with a blanket of Llanos deposits of terrestrial origin. These deposits consist largely of alluvial cones formed at the edge of the foot-hills, but grade southwards into great sheets of alluvial clays and sands over the main Llanos.

(*f*) The final stage consisted of a considerable upward movement associated with a partial dissection of the Llanos deposits near the foot-hills.



Tectonical Sketch Map of
TRINIDAD & EAST VENEZUELA
Scale
Showing position of Oilfields and exploration wells
Cretaco-eocene basement rocks
Folds
✱ Oilindications in Venezuela
G Gas
P Oil
A Asphalt
V. Mudvolcano
▲ Exploration well
Oilfields
1 Tabaquite
2 Brighton
3 Vessigny
4 Parrylands
5 Fyzabad
6 Barrackpore
7 Point Fortin
8 Los Bajos
9 Palo Seco
10 Guayaguayare
11 Quirequire
12 Guanoco
13 Pedernales
Isla de Margarita
LA ASUNCION
TRINIDAD
Pto ESPAÑA
Golfo de Paria
Central Range trend
Golfo de Cariaco
CUMANA
BARCELONA
CARUPANO
RIO CARIBE
GÜIRIA
MACURO
MATURIN
Maturial
Hervedero
El Bombal
Quiriquire
Orocual
CAÑO COLORADO
Guanoco
Amacuro
PEDERNALES
Pedernales
TUCUPITA
BARRANCAS
URACOA
Tabasca
Templador
Pilon Nº 1
El Salto
Tigre Nº 1
Oficina Nº 1
Oficina Nº 2
Merey
Areo Nº 1
Canoa Nº 1
Canda Nº 2
Sta. Rosa Nº 1
Sta. Ana Nº 1
El Lirial
CIUDAD BOLIVAR
SOLEDAD
MOITACO
BOCA DEL PAO
CURIAPO
PIACOA
MAPIRE
ANZOATEGUI
MONAGAS
SUCRE
DELTA AMACURO

The Guayuta shales, where freshly exposed in the foothill regions, show considerable evidence of petroleum, and where they have been covered by sands of younger age they have impregnated the latter with asphaltic oil. The Guanoco oil is almost entirely Cretaceous, but its production is not commercial.

The exploited area at **Quiriquire** trends N. 70° E. for about 6 miles and is 3 miles wide. The productive Quiriquire formation is correlated with the La Brea beds of Trinidad, and attains a thickness of about 3,300 ft. in the south of the field. Inspissated oil is found throughout the Quiriquire formation, but the main production is from the lower 600 ft. in irregular sand bodies within silts and at times in conglomerates, capped by clays. These beds rest unconformably on Lower Miocene and Oligocene black shales. Towards the north they overlap petroliferous Eocene and Cretaceous. The oil is almost certainly migrant, and may have been derived from the Cretaceous or alternatively from Miocene or Oligocene beds farther down the flanks of the main basin.

The structure appears to be a monocline dipping SSE. at about 10°. At the northern edge of the field a strike fault with southern downthrow occurs, and cross-faults are frequent. These are marked by oil seeps, hard asphalt dykes, and the occurrence in places of shallow oil production near them. A slightly saline edge-water under considerable head bounds the field on the south. The wells range from 1,800 to 3,300 ft. in depth, and the maximum thickness of the productive zone is 750 ft. The oil is a dark green asphalt-base crude and has a gravity of 13–24·4° API.

About 7 miles WSW. of Quiriquire several wells have been drilled in the **Orocual** area, and it appears that continuity of the producing formations between the two areas may be expected. At Orocual productive beds, which may be equivalent to the Forest-Cruse formation, are known below the Quiriquire formation.

Four wells have been drilled at **Pedernales** into the Forest-Cruse beds and oil in commercial quantities has been proved. The tectonic complexities in this area are comparable to those of the Cedros Peninsula in Trinidad.

With the exception of the depths attained few data are available concerning the many exploratory wells (see sketch-map for locations). Despite this lack of information there is a belief that oilfields comparable to Quiriquire are present also in the State of Anzoategui and in southern Monagas.

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COLOMBIA AND THE MARACAIBO BASIN

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Geographical Distribution

Physical Features.

THE dominating topographic and structural feature of north-western South America is the Andean chain of mountains which extends across Colombia and Venezuela in several distinct north-easterly trending branches. In Colombia these ranges are known as the Cordillera Occidental, Cordillera Central, and Cordillera Oriental. Upon reaching the Venezuelan border, the latter range divides into the Sierra de Perijá and the Sierra de Merida. The Sierra de Perijá extends northerly and north-easterly towards the Goajira Peninsula, while the Sierra de Merida trends north-easterly, and then nearly easterly across Venezuela towards Trinidad. The Cordillera Central and the Cordillera Occidental are not sharply differentiated in northern Colombia and merge to form a single range which trends north-westerly into the Panama range.

In northern Colombia and the Maracaibo Basin the highland areas and the intervening depressions form the following geographic divisions:

Cordillera Occidental.
Cordillera Central.
Cordillera Oriental.
Sierra de Merida.
Sierra de Perijá.
Sierra Nevada de Santa Marta.
Maracaibo Basin.
Magdalena Valley.
Cauca Valley.
Atrato Valley.
Pacific Slope.

Petroliferous Areas.

The present production is confined to the Maracaibo Basin and the Magdalena Valley, but oil-bearing formations and evidences of petroleum are more widespread. The entire Maracaibo Basin is covered with formations which, under favourable structural conditions, might be oil bearing. The Colombian production is all drawn from the upper Magdalena Valley in the State of Santander. Nearly all of it is from the De Mares concession. Petroliferous rocks, however, are present in the lower Magdalena Valley, whence some production has been drawn. Oil and gas seepages, mud volcanoes, and other evidences of petroleum are numerous in a zone extending from the lower Magdalena Valley south-westwards to the valley of Rio Atrato. The location of the producing fields is shown in the Map.

Geological Distribution

The oil-bearing and oil-generating beds of Colombia and the Maracaibo Basin comprise a series of sediments over 25,000 ft. thick which extend from the Cretaceous to the Pliocene in which nearly every major division is petroliferous.

The underlying beds comprise Early Cretaceous or pre-Cretaceous red beds and partially metamorphosed sediments which are apparently non-petroliferous. The basement rocks, however, have yielded locally a small production. Heavy oil seeps from basalt at Cachirí in the western part of the Maracaibo Basin, and in the Totumo field in the District of Perijá the production is drawn from igneous and metamorphic rocks.

During Early Cretaceous time both the Maracaibo Basin and north-eastern Colombia in common with much of northern South America became submerged by an epicontinental sea in which were deposited large bodies of limestone. Before the close of the Cretaceous, however, this depositional period was closed by a gradual general emergence, accentuated along the axes of the present sierras.

Following a long erosional period, the Tertiary sea again invaded the area, occupying partially separated basins lying between highland areas, which became depositional basins and remained so more or less continuously throughout the Tertiary epoch.

The basal Eocene deposits rest unconformably on Cretaceous and older rocks, and are the result of a depositional phase that extended on into the Oligocene and with some interruptions through the Tertiary. In the Maracaibo Basin this phase was brought to a temporary close by widespread uplift and erosion, but during the Middle Oligocene the region was again submerged, and this depositional cycle extended on into the Early Miocene. In Colombia the Oligocene emergence may have been more important, as in places the entire Oligocene section is missing and the Miocene rests directly on the Eocene and older deposits.

This Miocene submergence was followed by relative elevation and mountain folding which culminated in the Pliocene or at its close. This continued uplift restricted the depositional basins more and more and furnished the detritus for the accumulating sediments which were laid down as continental, estuarine, and marine deposits.

The Cretaceous sequence of the Maracaibo Basin is given in Table I.

TABLE I

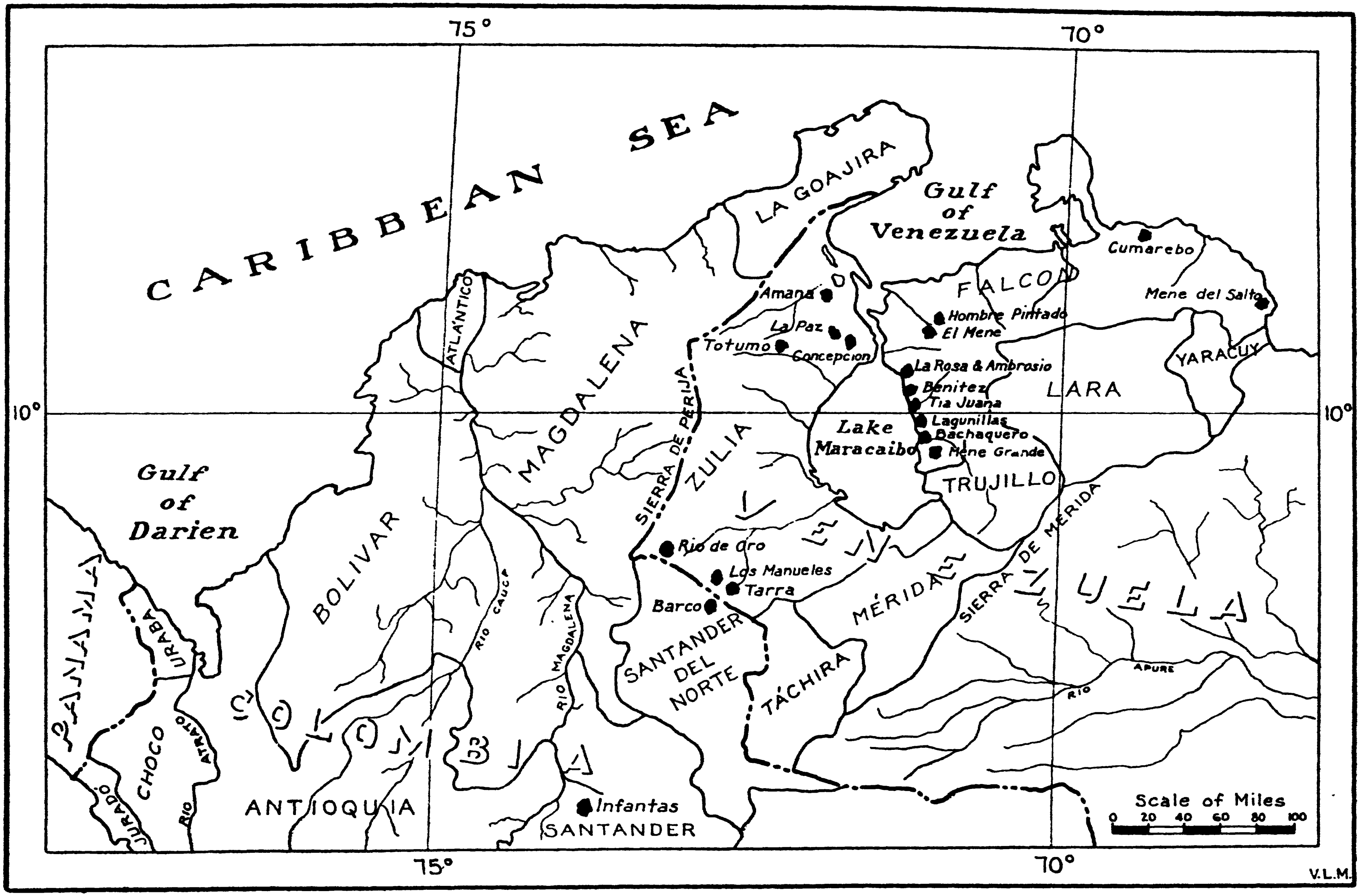
Cretaceous Sequence, Maracaibo Basin.

Tertiary sediments.
Unconformity.

Upper Cretaceous.
Colon shale—Petroliferous, dark-grey, foraminiferal shale with thin beds of hard grey sandstone and limestone concretions; 2,000–3,000 ft., Ammonites abundant.

Middle Cretaceous.
La Luna formation—Dark grey to black carbonaceous and petroliferous limestone; 2,000 ft., Megafossils rare but microfossils abundant, mainly *Foraminifera.*

Lower Cretaceous.
Cogollo limestone—Light grey limestone, petroliferous in fractures, but lacking in bituminous organic material. *Exogyra* abundant, but few pelagic *Foraminifera*; 1,500 ft.
Rio Negro conglomerate—Conglomerates and coloured sandstone with lenses of limestone and thin shales; 4,000 ft.
Unconformity.



Sketch-map of northern Colombia and the Maracaibo Basin, showing location of producing oilfields.

Rio Negro Conglomerate. The basal member is the Rio Negro conglomerate which was formerly called both the Lagunillas conglomerate and the Basal Cretaceous conglomerate. The formation consists of 4,000 ft. of non-fossiliferous conglomerates, red, yellow, and greyish coarse sandstones, limestone lenses, and shales. The conglomerate rests with marked unconformity on the eroded edges of red beds and older formations, and is correlated with the Barranquin formation of north-eastern Venezuela.

Cogollo Limestone. The type locality of the Cogollo limestone is the Rio Cogollo in the Sierra Perijá. It overlies the Rio Negro conglomerate conformably, although in places it overlaps pre-Cretaceous rocks. Liddle [6] in 1928 described it as hard, massive, grey or buff fossiliferous limestone and intercalated dark grey to black shales, 1,000 to 1,500 ft. thick. Locally it is nodular and cherty.

Hedberg [4] in 1931 published some petrographic details. It is typically grey or light grey. Molluscs, echinoid fragments, and bryozoans are common, and in places the rock is almost entirely composed of poorly preserved *Exogyra*, although it is almost entirely lacking in pelagic foraminiferal remains. Some beds are seemingly composed chiefly of calcareous algae, and algal remains are characteristic of the formation in general. In places it is sandy and phosphatic, but it is notably lacking in bituminous organic material.

The Cogollo limestone is petroliferous, but the oil is confined chiefly to fractures and is not diffused through the rock. The contained oil was probably derived from the overlying beds, and the Cogollo is not regarded as either a source or a reservoir rock.

The most common fossils are *Gryphea*, *Exogyra*, and *Ostrea*. It is correlated with the El Cantil formation of north-eastern Venezuela, of Lower Cretaceous age, the equivalent of the Aptian and Albian.

La Luna Formation. The La Luna formation is named from its typical exposure at Quebrada La Luna on the eastern flank of Sierra Perijá. It comprises the lower part of what has sometimes been included in the Colon shale and probably also the upper part of the section included in the Cogollo limestone. It was defined by Hedberg [4] in 1931 as a formation distinct from the Colon shale on account of its lithological character and from the Cogollo limestone on the basis of the marked faunal and lithological differences. He says that two distinct types of Cretaceous limestone exist which he terms a La Luna type and a Cogollo type. These can be clearly differentiated, but at most places no definite line of contact can be drawn between them because of the interbedding of the two types, but the Cogollo type is predominant in the lower part and the La Luna in the upper part.

'The La Luna limestone in typical development is dark grey to black. The formation is characteristically more thin-bedded than the underlying Cogollo limestone and is in many places finely laminated. It is particularly characterized by black, ellipsoidal, limestone concretions ranging from a few inches to several feet in diameter. Many of these concretions, when broken, show well preserved mollusk shells as nuclei. Megascopic fossils are in general rare, although a profusion of fish scales is characteristic of parts of the formation. When freshly broken, some of the limestone has a strong petroleum odor. Black chert is common as seams and nodules. The total stratigraphic thickness of the formation may be as much as 2,000 ft. in this area, but exposed thicknesses are markedly different because of faulting....

'Under the microscope the black La Luna rock is seen to be composed almost entirely of tests of small pelagic *Foraminifera* (*Globigerina*, *Globorotalia*, *Globotruncana*, *Guembellina*, et cetera). . . . Large fossils are almost completely absent, and there is little or no coarsely crystalline calcite. There is very little sand impurity.'

As already noted, the La Luna limestones are more or less petroliferous throughout, the oil being uniformly diffused and probably indigenous to the formation. The foraminiferal test cavities are generally filled with clear crystalline calcite, and the surrounding matrix is composed chiefly of dark grey or black carbonaceous and bituminous matter.

It is correlated with the Villeta formation of Colombia of Middle Cretaceous age, and with the Guayuta formation of eastern Venezuela.

Colon Shale. The type locality of the Colon shale is the District of Colon in the western part of the Maracaibo Basin, where the beds crop out on the eastern flanks of the Sierra Perijá. It consists of 2,000 to 3,000 ft. of dark grey foraminiferal shales with thin beds of hard grey sandstone and limestone concretions. The Colon shale conformably overlies the La Luna formation with which it was formerly grouped. It is the equivalent of the upper part of the Guayuta formation of eastern Venezuela.

It contains *Exogyra*, *Enallaster*, *Cucullaea*, *Ostrea*, *Cardita*, *Astarte*, *Cythera*, *Baculites*, *Schloenbachia*, and other forms. Liddle [6] in 1928 said that the great number of ammonites and pelecypods found in these shales indicates that they are Upper Cretaceous, including at least the Cenomanian and Turonian. The uppermost Cretaceous is not known.

The Colon shale is a productive horizon. Its outcrop produces many active seepages, and within the limestone concretions many fossils are found, in the body-cavities of which liquid asphaltic oil is common.

Cretaceous of Colombia. The Cretaceous of Colombia consists of 20,000 ft. or more of sediments of which no complete conformable sequence has been established. The sequence suggested by Anderson [1] in 1926 is given in Table II.

TABLE II

Cretaceous Strata in Colombia

By F. M. ANDERSON

Tertiary sediments.
Unconformity.

Upper Cretaceous.
Guadalupe group—Sandstone and sandy shales; dark clay shales, usually hard; siliceous shales or cherts, with *Foraminifera*, but with few fossil molluscs; contain locally lignitic or carbonaceous beds; 4,000 ft.

Middle Cretaceous (Aptian and Albian).
Villeta group—Grey or dark clay shales and sandstones; thin-bedded limestones, more or less bituminous; marls sometimes sandy, with echinoids, *Asterias*, and near-shore molluscs; locally richly fossiliferous shales and limestones; 1,500–2,000 ft.

Barremien and Hauterivien.
Suarez group—Red sandstone, locally very thick; thin-bedded limestones and marls, with *Crioceras*, *Hoplites*, *Puzosia*, &c.; 1,500–2,000 ft.

Lower Cretaceous.
Jiron group—Red sandstones and variegated sandy shales without fossils; white sandstones, often in thin beds; local conglomerates; 10,000–12,000 ft.

Jiron–Suarez Groups. Neither the Jiron nor the Suarez group appear to be probable oil horizons.

Villeta Group. The bituminous limestones and seepages of asphaltic oil in the Villeta have led to statements that it is a source rock of oil. Actual production from it has not been obtained, although its equivalent, the La Luna limestone, is a probable source rock.

Guadalupe Group. The Guadalupe group composed of sandstones, sandy shales, and white siliceous shales also contains bituminous strata and seepages of oil.

Tertiary.

Tertiary rocks are widespread over the Maracaibo Basin and northern and western Colombia. The Maracaibo Basin deposits are limestone, sandstone, and shale of marine, estuarine and lacustrine origin, representative of all the major Tertiary divisions. The condensed section is shown in Table III.

TABLE III

Tertiary Stratigraphic Section, Maracaibo Basin

Pliocene.
El Milagro beds—Micaceous and ferruginous sandstone and arenaceous shales with petrified wood
Mene Grande series—Mottled clays and petroliferous sandstone; 12,000–4,800 ft.
Unconformity.

Upper Miocene.
La Villa beds—Conglomerates, clay shales, and sandstones; Guayabo formation—Arenaceous and argillaceous beds with seams of coal; 2,500 ft.

Middle Miocene.
Damsite formation, Palmarejo beds, Los Ranchos beds, Upper Shale horizon—Greenish to greyish selenitic clay shales and interbedded marly fossiliferous limestone; 1,500–4,000 ft.

Lower Miocene.
First Coal horizon—Lignitic sandstone, shale, and calcareous beds; 2,000 ft.
Cerro Pelado formation—Flaggy sandstone and shale; 4,000 ft.

Upper Oligocene.
Agua Clara formation—Light grey, concretionary, fissile, petroliferous shale and limestone; 1,300 ft.

Middle Oligocene.
San Luis formation—Massive coraline limestone with conglomeratic sandstone and conglomerate; 1,000 ft. thick; *Lepidocyclina* and other fossils.

Upper Eocene.
Paují formation—Massive grey to black fissile shale and hard buff and grey sandstone; 3,000 ft.
Unconformity.
San Pedro formation—Hard, steel-grey, foraminiferal limestone; few feet thick; *Orthophragmina, Lepidocyclina.*
Unconformity.

Middle Eocene.
Mirador sandstone—Conglomeratic to fine-grained, hard, massive, buff sandstone with shale and coal; *Halyminites, Venericardia, Turritella, Ostrea*; 2,000 ft.

Lower Eocene.
Third Coal horizon—Nearly pure shale with lenses of fossiliferous limestone and in the basal part sandy beds with coal; 1,200 ft.
Unconformity.

Cretaceous sediments.

The Colombian Tertiary also includes a variety of sediments of marine-, brackish-, and fresh-water origin, the marine section occurring along the coast and becoming progressively less marine in character towards the highlands. Condensed stratigraphic sections are shown in Tables IV and V.

TABLE IV

Tertiary Stratigraphic Sequence, Lower Magdalena Valley and Sinu Valley

Pliocene.
Coral limestone and sandstones; *Cyprea, Pecten, Codakia,* oysters, gastropods.
Probable unconformity.

Upper Miocene.
Galapa–La Popa group—Sandy shale, clay marl, calcareous sandstone; 1,500 ft.; *Pecten, Dosinia, Cardium.*
Possible unconformity.

Middle Miocene.
Tubera group—Fossiliferous sandstone and sandy shale.

Lower Miocene.
Las Perdices group—Clay shales, sandy shales, sandstone, siliceous beds; Mollusca, *Foraminifera.*

Oligocene.
Poso series—Fossiliferous sandstone and shale.
Unconformity.

Eocene.
Carmen group—Fossiliferous marine beds with intercalated coal deposits; *Operculina, Lepidocyclina, Nummulites.*

TABLE V

Tertiary Stratigraphic Sequence, Upper Magdalena Valley

Pliocene.
Honda beds—Sandstone, clay, and tuffaceous sediments; 800 ft.
Unconformity.

Miocene.
Oponcito-Barzalosa beds—Red conglomerate, tuffaceous sandstone, carbonaceous shale; 3,000 ft.
Unconformity.

Eocene.
Guaduas beds—Fossiliferous coal-bearing sandstone and shale; 10,000 ft.
Unconformity.

Eocene.

Misoa-Trujillo Formation. The Misoa-Trujillo formation is named from the sierras in the eastern part of the Maracaibo Basin. Its two members, the Third Coal horizon and the overlying Mirador sandstone, take their names from the District of Colon in the south-western part of the Maracaibo Basin.

The basal Eocene member is the Third Coal horizon, which unconformably overlies the Cretaceous sediments. It is composed of about 1,200 ft. of almost pure shale which becomes sandy towards the base, where it contains workable coal seams. Locally it contains lenses of impure fossiliferous limestone, and pyritic and ferruginous bands. The overlying Mirador sandstone member, separated from the Third Coal horizon on lithology, consists of 2,000 ft. of conglomeratic to fine-grained, hard, massive, buff sandstone with interbeds of shale and coal.

Venericardia planicosta Lamarck and *Turritella mortoni* Conrad are characteristic index fossils of the shale horizon, and *Ostrea bellovacina* Lamarck, *Calyptrahorus trinodiferus* Conrad, and *Ostrea alabamensis* Lea also occur. On the island of Toas in Lake Maracaibo an oyster reef in calcareous sediments contains *Ostrea crenulimarginata* and other forms. The Mirador sandstone member is practically barren of fossils, but locally has yielded *Halyminites.* It is correlated with the Midway, Wilcox, and probably also the Claiborne, and is the probable equivalent of the Ortiz and Aragua formations of eastern Venezuela, which have yielded a large fauna.

The Misoa-Trujillo formation is widely distributed in the Maracaibo Basin. It produces seepages of high-grade

oil and is a productive horizon at Mene Grande, Tarra, La Paz, La Concepcion, Punta Benitez, and several fields on the north-eastern shore of Lake Maracaibo.

San Pedro Formation. The type locality of the San Pedro formation is the Rio San Pedro in the eastern part of the Maracaibo Basin. It consists of only a few feet of hard, steel-grey, foraminiferal limestone lying unconformably on the Mirador sandstone. It contains abundant *Orthophragmina* and *Lepidocyclina*, also other *Foraminifera*. It is regarded as Jackson, and is correlated with the Soldado formation of eastern Venezuela.

Paují Shale. The term Paují shale was first applied to beds in the Rio Paují in the eastern part of the Maracaibo Basin, where it is apparently conformable on the San Pedro formation. It consists of 3,000 ft. of massive grey to black, fissile, micaceous shales, locally calcareous or gypsiferous, alternating with hard, fine-grained, buff to grey sandstone with local quartz or calcite stringers. Ironstone and pyritic concretions weather into characteristic red splotches. It is a productive horizon at Mene Grande and other fields.

The Paují shale is widespread over the Maracaibo Basin, in the south-western part of which it is known as the Sandy Shale horizon, a term which may include also overlying beds including Lower Miocene.

The Paují shale is correlated with similar deposits throughout Venezuela. It has been regarded as lower Oligocene, but on the basis of its *Foraminifera* it was stated by Nuttall [7] in 1935 to be Upper Eocene.

Carmen Group. In the lower Magdalena Valley and the west coast, Eocene formations which Anderson [1] in 1926 referred to locally as the Carmen, Arjona, and Tofeme-Coloso groups, and the San Sebastian cherts, consist of fossiliferous marine beds with intercalated coal deposits. He gives the following section at El Carmen on the Lower Magdalena.

TABLE VI

Eocene Sediments, Lower Magdalena

By F. M. ANDERSON

Clay shale, sandy clay shale, white siliceous shale, probably organic (not known to be the top)	1,000 ft.
Concretionary sandy shale, sandstone, &c., with molluscan fossils, *Foraminifera*, petrified wood, &c.	600 ,,
Yellow, thin-bedded sandstone, weathering red	400 ,,
Whitish shale, with lenses and thin beds of limestone, sandstone, &c. (Tofeme group, with thin beds of lignite and carbonaceous matter near bottom)	800 ,,
Earthy or hard, thin-bedded, siliceous shale, marly shale with limestone, containing molluscan fossils	800 ,,
Yellow concretionary sandstone	500 ,,
Heavy beds of sandy conglomerate (near Cansona)	400 ,,
Total	4,500 ,,

This section is the part equivalent of the strata described in 1921 by Beck [3] as the Palmito limestone, and by Werenfels [9] in 1926 as the Arroyo Seco formation and the Toluviejo series. The Arroyo Seco is described as conglomerate overlying black shale, and the Toluviejo as snow-white massive limestone with *Helicolepidina*, *Lepidocyclina*, *Nummulites*, and *Operculina*.

Guaduas Beds. Estuarine and lacustrine deposits in the central and upper valley of the Magdalena correlated with the marine Eocene, although possibly in part Oligocene, include the Guaduas beds named by Hettner [5] in 1892, and equivalent strata. They consist of 10,000 ft. of fossiliferous coal-bearing sandstone, shale, and eruptive rock which rest unconformably on the Guadalupe formation. The estuarine phase contains *Ampularia graduasensis*, n.sp., *Melanella magdalenensis*, n.sp., *Corbula Hettneri*, n.sp., *Cyrena Karsteni*, n.sp., and numerous plant remains.

Both the marine and non-marine Eocene formations contain much organic material and are highly petroliferous, containing numerous oil and gas seepages, asphaltic residues, mud volcanoes, and bituminous sands. It is the productive horizon and probably also the source rock at Las Infantas and other fields.

The Colombian Eocene is correlated with the Wilcox and Claiborne, and is the probable equivalent of the Third Coal horizon and the Mirador sandstone of the Maracaibo Basin. It lies unconformably on the Cretaceous and older rocks.

Oligocene.

San Luis Formation. The type locality of the San Luis formation is Sierra de San Luis in the State of Falcon. In the Maracaibo Basin it conformably overlies the Paují shale. It consists of massive, steel-grey, coralline limestone, dark shale, and coarse, grey, conglomeratic sandstone and conglomerate. It is widely distributed in the eastern part of the basin, where it has a maximum thickness of about 1,000 ft., but pinches out towards the west. The Maracaibo Basin exposures form the western part of a coral reef which reached its best development in the State of Falcon. Besides the abundant corals, it contains many *Lepidocyclina* and other fossils. It is regarded as Middle Oligocene, and is correlated with the Tamana formation of Trinidad.

Agua Clara Formation. The Agua Clara shales were named from their typical exposures near Santa Clara in the State of Falcon. In the Maracaibo Basin it is apparently conformable on the San Luis formation and is known from widely distributed outcrops and from well cuttings. It consists of 1,300 ft. of light grey, concretionary fissile, gypsiferous shales alternating with hard, flaggy, light grey, fossiliferous limestone of upper Oligocene age.

The Agua Clara formation is very petroliferous, and is the most important oil horizon of the basin. It contains two important horizons about 200 ft. apart known as the Santa Barbara and La Rosa sands, which are the producing horizons in most of the fields.

Poso Series. The Oligocene of Colombia is probably best known by the name of Poso Series, a term applied by Anderson [2] in 1929 to the entire sequence lying between the Eocene and known Miocene, including strata previously described as the San Juan group of the Magdalena Valley and the Bombo shales of the Rio Sinú. The term was suggested by the fact that this assemblage was being tested for petroleum. The type locality is the general region of the Rio Sinú at which place they unconformably overlie the Eocene, but in other places the Oligocene is missing entirely. Their thickness and character are shown in Table VII.

TABLE VII

Stratigraphic Section of Poso Series, Rio Sinú, Colombia

By BRUCE G. MARTIN

Alternating, hard, coarse sandstone and medium-grained sandy shale	1,000 ft.
Medium-soft, fine-grained, bluish-grey sandstone and clay, with some concretionary limestone lenses	1,500 ,,
Medium-coarse, hard, grey sandstone and medium-soft, blue or grey sandstone	900 ,,
Total	3,400 ,,

Unconformity.
San Sebastian cherts, &c. (Eocene).

He gives the following section in the Palomas Range, where the sediments show a more shaly facies.

An upper shale and sandstone member	1,500 ft.
A sandstone and grit member	2,000 „
A basal shale member	1,500 „
Total	5,000 „

The Poso series are not very fossiliferous, but their general stratigraphic position indicates that they are post-Eocene and in part or altogether pre-Miocene. They are the source of numerous seepages of oil and gas and of mud volcanoes.

Miocene.

Cerro Pelado Formation. The term Cerro Pelado is applied to an assemblage of rocks typically exposed in the eastern part of the Maracaibo Basin and in the State of Falcon. They conformably overlie the Agua Clara beds and include 4,000 ft. of thin, alternating, reddish-brown, flaggy, micaceous sandstone and mudstones in the upper part and massive, cross-bedded sandstones in the lower part. Their equivalent in the western part of the Maracaibo Basin has been included in the lower part of the Sandy Shale horizon.

Socorro Formation and First Coal Horizon. The Socorro formation of Falcon occurs in the eastern Maracaibo Basin. It lies conformably above the Sandy Shale horizon into which it grades, and consists of 2,000 ft. of micaceous, ripple-marked, and cross-bedded, lignitic sandstones, grey and brown micaceous shales, and a few calcareous beds. Its equivalent in the western part of the basin is included in the First Coal horizon which is productive in the Tarra and Los Manueles fields.

Damsite Formation. The Damsite formation was named from its typical exposure at a dam site on the Rio Coro in the State of Falcon. It is predominantly greenish and grey selenitic clay shale with interbeds of marly, fossiliferous, yellow to bluish-grey limestone, and is gradationally conformable on the Socorro formation.

Equivalent beds in the western and south-western part of the Maracaibo Basin are the Palmarejo beds, the Los Ranchos beds, and the Upper Shale horizon. The Palmarejo beds crop out on the western shore of Lake Maracaibo. They consist of 2,000 ft. of grey micaceous shales, arenaceous shales, and hard, grey, ferruginous sandstones. The Los Ranchos beds exposed on the eastern flank of the Sierra Perijá are made up of 4,000 ft. of conglomerates, conglomeratic sandstones, grey and brown, ferruginous, mottled sandstones, and clay shales. The Upper Shale horizon is a series of soft arenaceous shales and carbonaceous sandstones which crop out in the south-western part of the basin. The stratigraphic relationships of these beds are obscure, but the Upper Shale horizon, the Los Ranchos beds, and the Palmarejo beds are all probably the part equivalent of the Damsite formation.

La Villa Beds. The type locality of the La Villa beds is the town of that name in the western part of the Maracaibo Basin. They are apparently gradationally conformable on the Los Ranchos beds and together are sometimes referred to as the Arimpia formation. The La Villa beds consist of 2,500 ft. of conglomerates and vari-coloured mottled clay shales and cross-bedded and poorly consolidated sandstones. Their probable equivalent in the south-western part of the basin is known as the Guayabo formation, named from the Guayabo hills. It is locally unconformable on the Upper Shale horizon. Lithologically it resembles the La Villa, but contains several seams of coal.

Magdalena Valley. The Miocene of north-western Colombia also occurs in marine, brackish, and fresh-water facies. A marine section occurs along the coast and the lower Magdalena Valley, but becomes progressively less marine in character towards the highlands.

These strata have been described by various names with local significance. Beck [3] in 1921 described the basal Miocene as the Huertos limestone series consisting of limestone and sandstone, and the upper part as the San Antonio Sandstone formation. To the same section exposed at Toluviejo, Werenfels [9] in 1926 applied the names Cerrito formation and Savana sandstone.

The known Miocene of the lower Magdalena Valley was later divided by Anderson [2] in 1929 into two sections to which he assigned the names Las Perdices and Tuberá groups, and included with them as probably Miocene with the overlying Galapa–La Popa group.

Las Perdices Group. The Las Perdices group comprises 1,000 ft. of strata which appear to be in the basal part of the lower Magdalena Miocene. It consists of clay shales, sandy shales, and hard cherty, or siliceous beds and some sandstone, and contains a few Mollusca and many *Foraminifera.* This same horizon at Toluviejo and Sincelejo contains notable amounts of sandy limestone.

Locally the lowest known Miocene shows an unconformable relationship to the Pozo series, although it is not certain that this unconformity occurs at the contact of the Oligocene and the Miocene, or that it is general or important.

Tuberá Group. The term Tuberá group was used for the overlying sequence which crops out typically in the vicinity of Tuberá. It consists of 2,650 ft. of incoherent sandstones and sandy shales, and constitutes the most widely distributed and the more usual facies of the Colombian Miocene. It overlies the Las Perdices group with apparent disconformity. It is highly fossiliferous. Many of its fauna have been figured and described by Anderson who correlates its middle upper part with the Gatun formation.

Galapa–La Popa Group. Overlying the Tuberá group with apparent conformity is a sequence of beds, portions of which have been termed the Galapa, La Popa, Arbolete, and Escondido groups, usually regarded as Pliocene. Anderson [2] in 1929 considered them as probably Upper Miocene, in part at least, and conformable on the Tuberá group. They consist of sandy shales, clays, marls, and calcareous sandstone, 1,500 ft. or more thick, and carry an abundant marine fauna with *Pecten, Dosinia,* and *Cardium.*

Barzalosa Beds. The non-marine Miocene of the central upper parts of the Magdalena Valley were named the Barzalosa beds in 1918 by Scheibe [8]. They and their probable equivalent, the estuarine Oponcito series, consist of red conglomerate, tuffaceous sandstone, and carbonaceous shale, in places 3,500 ft. thick. They are unconformable on the older formations. In places the entire Oligocene is absent, and they rest upon the Eocene.

The Miocene beds of Colombia are low in organic content and are not important as source rocks. They are, however, petroliferous in places and appear to be possible reservoir sands where favourable structural conditions obtain.

Pliocene.

Maracaibo Basin. The early Pliocene appears to have

been a period of uplift and erosion, followed by marine and fluviatile deposition. In the Maracaibo Basin the Mene Grande series has a thickness of 1,200 to 4,800 ft. and unconformably overlies the Miocene and older formations. It consists of mottled clays with a few lenticular bodies of sand, non-fossiliferous except for a few *Foraminifera*. The overlying El Milagro beds are ferruginous, sandy, micaceous clay and loosely consolidated, cross-bedded sands with silicified wood.

Lower Magdalena Valley. In Colombia the Pliocene consists of marine and non-marine deposits which are apparently unconformable on all the older formations. Near Barranquilla and Cartegena they are represented by coralline limestones and sandstones. Anderson [2] published the following sequence in 1929.

TABLE VIII

Pliocene Strata between Puerto Colombia and Salgar, near Barranquilla

By F. M. ANDERSON

Upper coral limestone	250 ft.
Incoherent sandstones	350 „
Lower coral limestone	160 „
Sandy clay shales	150 „
Total thickness	910 „

The limestones contain corals and mollusca including *Cyprea*, *Codakia*, *Pecten*, oysters, and gastropods.

Honda Beds. The Honda beds are composed of greenish-grey andesitic tuff, tuffaceous sandstone, clay, and conglomerate which unconformably overlie the Barzalosa and older formations in the Upper Magdalena Valley. Their stratigraphic position suggests that they are Pliocene.

The Pliocene strata are in places highly petroliferous. The Honda beds contain bituminous sands and oil seepages, and oil and gas seepages with sulphurous water are found also in the Pliocene deposits of the coast. The Mene Grande series is petroliferous and has produced some oil.

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ECUADOR

By H. G. BUSK, M.A., F.G.S., M.Inst.P.T.

Geologist

PETROLEUM in commercial quantities has been proved to exist in Ecuador on the west coast in the Santa Elena Peninsula, on the western side of the great estuary of the River Guayas (Fig. 1). It occurs in rocks of the same age and of similar lithology as those of Peru, namely, in Eocene and Oligocene clays and sandstones. Exact correlation, even for short distances, is extremely difficult, owing to the shattered and crushed nature of the country, the rocks of which may be regarded as forming a great tectonic breccia, the geological units of which may be of microscopic size or up to 3 and 5 miles across. This is further complicated in Ecuador by the intrusion of dolerites during the time that these disturbances were taking place.

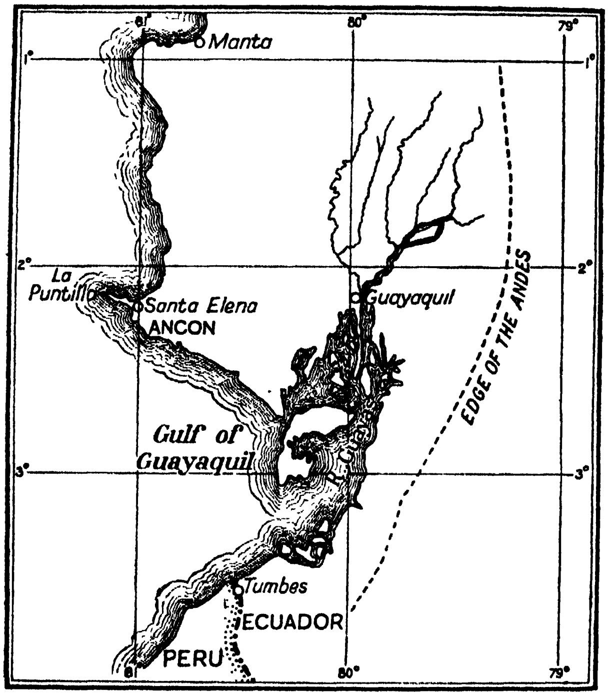

FIG. 1.

The Peninsula of Santa Elena, from which petroleum is at present being successfully produced, may be divided into two parts (Figs. 2 and 3):

(1) The southern part, which is occupied by rocks whose dips are generally less than 10° at the surface, but which are none the less greatly disturbed by tear faults and low-dipping planes of movement.

(2) The northern part, in which dips are seldom less than 70° (generally in a southerly direction), and where intruded dolerite is involved intimately with the disturbed beds, and is itself crushed and brecciated.

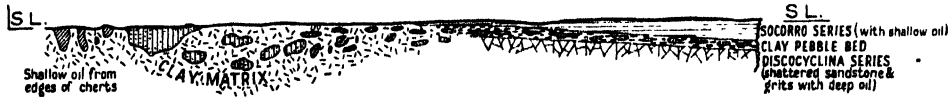

FIG. 3. General section through the Santa Elena Peninsula. The fragments of sandstone in the clay matrix of the northern area are believed to be mostly of Oligocene age, while the Socorro Series is Eocene. The exact relationship between the northern and southern areas is still obscure.

In the *southern part* of the peninsula, occupied by the Ancon oilfield, commercial oil, varying between 36° and 42° Beaumé, and containing between 30% and 70% gasoline, is found in two zones.

'Shallow oil' is found from the surface to 1,000 ft. in a series of alternating clays, silts, and sands (Socorro Series, Upper Eocene). Fossils are rare, apart from abundant *Foraminifera*, the chief of which are: *Lepidocyclina peruviana, Helicolepidina polygyralis* [8, 1932], *Operculina oculana*. The oil found in these rocks has a naphthene base, and is termed 'low cold test', being rich in lubricants. This property is ascribed to the oil's proximity to the ground surface.

'Deep oil' is found from 2,500 ft. to 3,500 ft., and is produced from a series of massive non-porous sandstones and grits, of which over 1,000 ft. have been proved. The oil is contained in fissures in the sandstones, which are shown by the core-taker to be highly brecciated. The age of this series, which at the top yields abundant *Foraminifera* is probably Upper, but may be Middle Eocene. Two

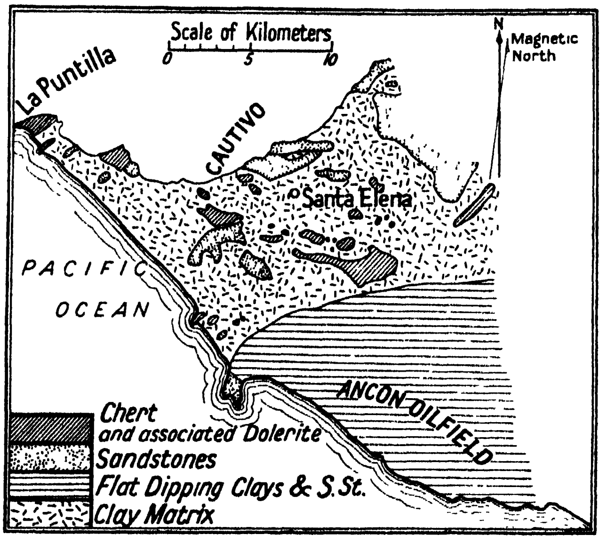

FIG. 2. Map of the Santa Elena Peninsula, showing distribution of sandstones and cherts in the clay matrix of the northern area, and the extent of the flat dipping rocks of the Ancon oilfield.

species of *Discocyclina*, *D. anconensis* and *D. sheppardi*, which do not occur elsewhere [8, 1932], have led to the adoption tentatively of the term 'Discocyclina Series' for these rocks. The oil is 'high cold test' and has a paraffin base.

Between these two series is a formation known as the 'clay pebble bed', whose origin has given rise to considerable controversy. It is barren of oil, and separates sharply the 'low' and 'high cold test' types of the shallow and deep zones. It varies rapidly in thickness, in one place from 100 to 1,300 ft. in less than a kilometre, and consists of a matrix of formless compacted clay, which breaks across slickensided surfaces; this matrix contains pebbles of many kinds, but chiefly of quartzite or of clay, the latter being well rounded and with a slickensided or shiny surface. There is no doubt that this rock resembles an old surface landslip breccia, but from the widespread occurrence of similar rocks, both in a lateral and a vertical sense, and both in Ecuador and Peru, and from its general environment, it is beginning to be agreed that the formation is a breccia, lying between two series, which have moved relatively the one to the other.

The clay pebble bed contains fossils identical with those of the Socorro Series, with the addition of *Operculina wilcoxii*, and, in places, a fauna, associated with the beds immediately below it, appears 50 ft. above its base. It seems that the Socorro and Discocyclina Series may be regarded as tectonic units in the great coast breccia, and that the clay pebble bed is a modified form of the general matrix.

In the *northern part* of the peninsula an attempt has been made to separate the main sandstone units of the great crush breccia, the intervening material being classed together as 'clay matrix'. It is to be noted, however, that 'units' can be separated from the matrix right down to the size of pebbles and much smaller. The intrusions of dolerite, too, or the hot vapours associated with them have given rise to great masses of chert, which are now proved to be thermally altered clays of Tertiary age. These cherts and dolerites were also involved in the movements, which created the breccia.

The petroleum in the northern part of the peninsula is closely associated structurally with the dolerite intrusions and the cherts, though there is no evidence to show that they are connected with its origin. It appears that, as the dolerites were intruded, the petroleum was vaporized near the hot nucleus, and condensed on the edges of the zone of metamorphism. Thus it may be found in productive quantities in porcellanites, which are an intermediate form of alteration round the edges of the cherts. Wells drilled round these chert masses yield petroleums of great variety, some of 42° Beaumé with 60% gasoline, and others of a heavy type, but rich in lubricating fractions. The occurrence of petroleum is, however, again greatly complicated by the earth movements, and no case has yet been proved in the peninsula where a dolerite or a chert can be shown to be in its original place of contact with a clay or a sandstone. A very common form of contact between the dolerites and the clay is, for instance, where fragments of the harder rock have been stripped off and rolled into the clays in the form of boulders.

The Tertiary rocks of the whole area are largely masked by raised sea terraces, known as Tablazos, and little could have been worked out without some knowledge of the Peruvian coast, near the Negritos and Lobitos oilfields.

It is natural that, in a region so complicated, there should have been and still is considerable controversy regarding both stratigraphy and structure. Thus Cunningham Craig [4, 1920] regarded the cherts of the peninsula as 'oceanic strata' of Cretaceous age', and inferred from this a striking illustration of the downward migration of petroleum. Later observers are agreed that the cherts are altered Tertiary shales [5, 1926; 7, 1923]. Barrington Brown and Baldry in an original survey regarded the clay pebble bed as a tectonic breccia [1, 1925], while Sheppard regards this formation as a true clastic [6, 1927]. A general comparison with Peru is desirable. Bosworth gives a clear picture of the crushed and brecciated state of the oilfields region of that country. 'The land surface', he says [2, 1922], 'is divided up into long triangles and elongated quadrilaterals outlined by faults of considerable displacement. The larger blocks are further cut up into many parts by smaller faults.' And he adds [3, 1922]: 'There is no folding in the Tertiary, but the earth's crust is so intensely broken up by faults as to resemble a giant crush breccia.'

Recent research in the two countries may well provide a number of new theories on tectonics, which may also be applicable to the oilfields of the North American continent of the Pacific Coast.

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THE ARGENTINE REPUBLIC

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I. General

OUR knowledge of the distribution of petroleum in the Argentine is necessarily incomplete and imperfect. The Argentine has an area more than twelve times greater than that of Great Britain, whilst Great Britain has almost four times as many inhabitants as the Argentine. Until 12 or 15 years ago, most of the geological studies were carried out during long journeys on horseback and had mainly the character of preliminary reconnaissance work.

The thick mantle of Quaternary deposits which covers nearly one-half of the country, the subtropical and tropical forest in the north-east, the predominance of continental conditions since Carboniferous times, the rather uniform facies of the continental formations, their scanty fossil content, and, moreover, the frequent lack of a sure correlation of such fossils with the well-known faunas and floras of the northern hemisphere are some of the difficulties encountered in exploratory work.

II. Geographical

Politically the Argentine is a Federative Republic, composed of fourteen States called 'Provincias', which enjoy a certain autonomy, and ten territories, called 'Territorios Nacionales' or 'Gobernaciones', which depend directly upon the federal Government.

The names and the disposition of these provinces and territories are shown in Fig. 1.

Actually there are producing oilfields in the provinces of Salta and Mendoza and in the territories of Neuquén and Chubut: in the province of Jujuy and in the territory of Santa Cruz, oil and gas have been found by drilling. In the territory of Rio Negro wells drilled near an oil seepage have not found oil in commercial quantities, whilst in the territory of La Pampa an interesting oil seepage is known.

In the province of Santa Fé, without any surface indication of petroleum, two wells have found small shows of oil at considerable depths.

The most southerly indications of petroleum in this continent have been found in the Chilean territory of Magallanes, in the neighbourhood of Punta Arenas, nearly midway between two Argentine territories (Santa Cruz and Tierra del Fuego). Wells were drilled there and it was reported that they gave gas and a little oil.

The highest surface indication of oil in the Argentine is the oil seepage at Barro Negro de Tres Cruces (also known as Tejadas) in the Puna of Jujuy, more than 10,000 ft. above sea-level. The highest producing oilfields are those of the Mendoza province (4,000 to 5,000 ft.) and that of San Pedro y San Pablo in the province of Salta (about 3,200 ft.).

The lowest producing oilfield is that of Comodoro Rivadavia, where the deepest oil-producing horizons have been found nearly 2,500 ft. below sea-level. The deepest oil traces have been found in this oilfield at about 5,500 ft. below sea-level.

The approximate geographical location of the proven or prospective oilfields and of some exploratory wells and oil seepages of major importance are given below:

	Province or territory	*Latitude*	*Longitude*	
Lomitas-Vespucio-Tranquitas	Salta	22° 33′–22° 40′	63° 53′–63° 59′	producing oilfield
Deshecho Chico	,,	22° 41′	62° 26′	oil seepages
Aguas Blancas	,,	22° 44′	64° 20′	producing oilfield
Rio Pescado Y.P.F. 3	,,	22° 54′	64° 27′	oil-well
Barro Negro de Tres Cruces	Jujuy	22° 56′	65° 39′	oil seepage
Santa Cornelia	,,	23° 45′	64° 26′	oil seepage
Y.P.F. JE. 1	,,	23° 48′	64° 26′	exploratory well
Laguna de la Brea	,,	23° 50′	64° 26′	oil seepage
Garrapatal	,,	24° 5′	64° 55′	oil seepages
San Pedro FF.CC.E. 1	,,	24° 8′	64° 54′	abandoned oil-well
San Cristobal Y.P.F. 1	Santa Fé	30° 18′	61° 14′	exploratory well
Cacheuta	Mendoza	33° 5′–33° 7′	69° 4′–69° 6′	productive oilfield
Tupungato Camp	,,	33° 20′	69° 3′	new oilfield
Cerro Alquitrán	,,	34° 59′	69° 28′	productive oilfield
Mina Matilde	,,	35° 5′	69° 45′	oil seepage
Ranchitos	,,	35° 13′	69° 43′	oil seepage
Malargüe Y.P.F. 1	,,	35° 36′	69° 33′	exploratory well
Laguna Llancanelo	,,	35° 42′	69° 6′	oil seepage
Rio Barrancas	,,	36° 47′	69° 55′	oil seepage
Barda Baya de Puelén	La Pampa	36° 56′	67° 49′	oil seepage
Aucá Mahuida	Neuquén	37° 53′	68° 31′	asphaltite veins
Covunco Y.P.F. NC. 1	,,	38° 37′	69° 35′	exploratory well
Bajo Baguales, Y.P.F. NE. 1	,,	38° 49′	69° 1′	exploratory well
Plaza Huincul	,,	38° 52′–38° 58′	69° 2′–69° 14′	producing oilfield
Challacó	,,	38° 54′	68° 58′	oil seepages
Cerro Lotena	,,	39° 11′	69° 38′	oil seepage
Ñirihuau Y.P.F. 2	Rio Negro	41° 17′	71° 11′	exploratory well
Comodoro Rivadavia	Chubut	45° 40′–45° 54′	67° 22′–67° 50′	producing oilfield
Pampa del Castillo T. 2	,,	45° 47′	68° 4′	exploratory well
Cañadón Lagarto L. 4	,,	45° 42′	68° 10′	exploratory well
Cerro Abigarrado A. 4	,,	45° 49′	69° 3′	oil-well
Sierra San Bernardo A. 5	,,	45° 57′	69° 32′	exploratory well
Pampa Maria Santisima A. 1	Santa Cruz	46° 1′	69° 20′	gas-well
Chenque Bayo N. 1	,,	46° 18′	69° 6′	exploratory well

Some of these localities are shown (with the limitations imposed by so small a scale) in Fig. 2.

III. Stratigraphical

It is known that continental conditions prevailed generally throughout geological time on that part of the earth's crust which corresponds to the territory of the Argentine Re-

public. However, these continental conditions were interrupted by marine transgressions of moderate extent, during which the sea invaded one or another region (never extending over the whole country) in several epochs of the Older Palaeozoic and Devonian (northwestern Argentine), the Late Trias, Jurassic, and Older Cretaceous (Salta, Jujuy, southern Mendoza, Neuquén, western parts of Chubut, and Santa Cruz), the Newer Cretaceous (southern Mendoza, southwestern Pampa, north-eastern Neuquén, Rio Negro, eastern parts of Chubut and Santa Cruz, northern Tierra del Fuego), and the Middle Tertiary (certain parts of Santa Fé, Corrientes, Entre Rios, Buenos Aires, Rio Negro, Chubut, Santa Cruz, and Tierra del Fuego).

Some of these marine transgressions are of doubtful age, the marine fossils of the 'Horizonte Calcáreo' of Salta and Jujuy having been referred to the Triassic, to the Jurassic, and to the Cretaceous by different authorities.

In the Argentine petroleum is found in rocks of various ages, younger than the Devonian. The following are several examples:

Quaternary, continental: oil seepages in alluvial deposits of Santa Cornelia, Laguna de la Brea, Laguna Llancanelo.

Upper Tertiary, continental: oil-bearing sands of Tupungato.

Middle Tertiary (or older), continental: oil seepage of Ñirihuau, many beds with shows of oil and gas penetrated by the two deep holes drilled there.

Lower Tertiary or Upper Cretaceous: oil and asphalt of Cerro Alquitrán.

Upper Cretaceous, marine: oil seepage and bituminous outcrops of Barda Baya. Upper productive horizons of the Comodoro Rivadavia oilfield.

Upper Cretaceous, continental: oil seepages of Challacó; asphaltite veins of Aucá Mahuida; main productive horizons of the Comodoro Rivadavia oilfield; oil-bearing beds penetrated by exploratory wells in Pampa de Castillo, Cerro Abigarrado, Pampa Maria Santísima, and Chenque Bayo.

Lower Cretaceous, marine: some of the oil seepages of Rio Barrancas.

Upper Jurassic, marine: oil seepages of Ranchitos and Cerro Lotena.

Upper Jurassic, continental: oil-producing horizons of Plaza Huincul.

Lower Jurassic, marine: oil seepage of Barro Negro de Tres Cruces and Garrapatal, productive horizons of well

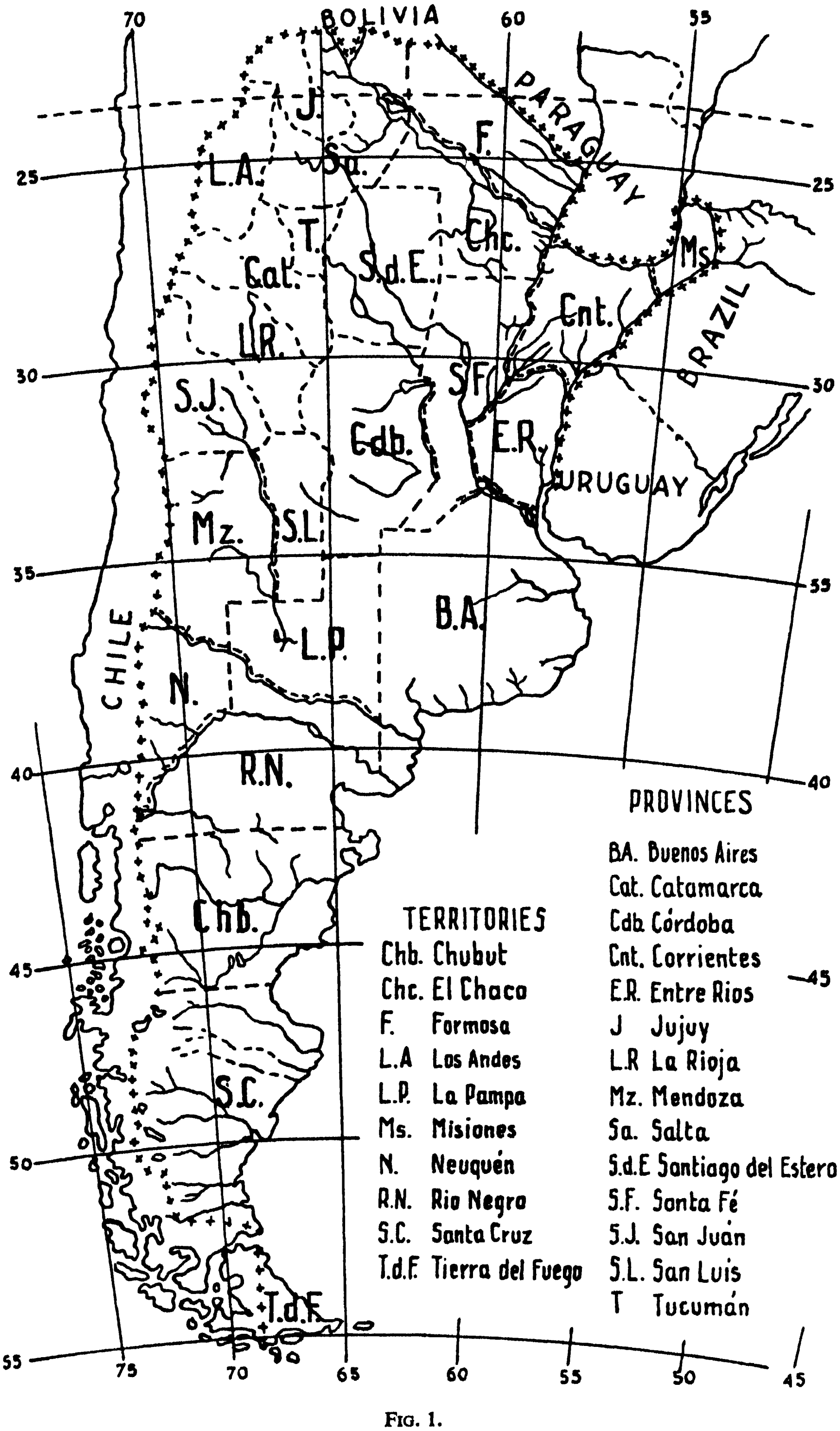

FIG. 1.

Y.P.F. JE. 1, uppermost oil-bearing beds of Tranquitas, oil seepage in the Mina Matilde.

Uppermost Triassic (*Rhaetic*), continental, lacustrine: productive horizons in the oilfield of Cacheuta.

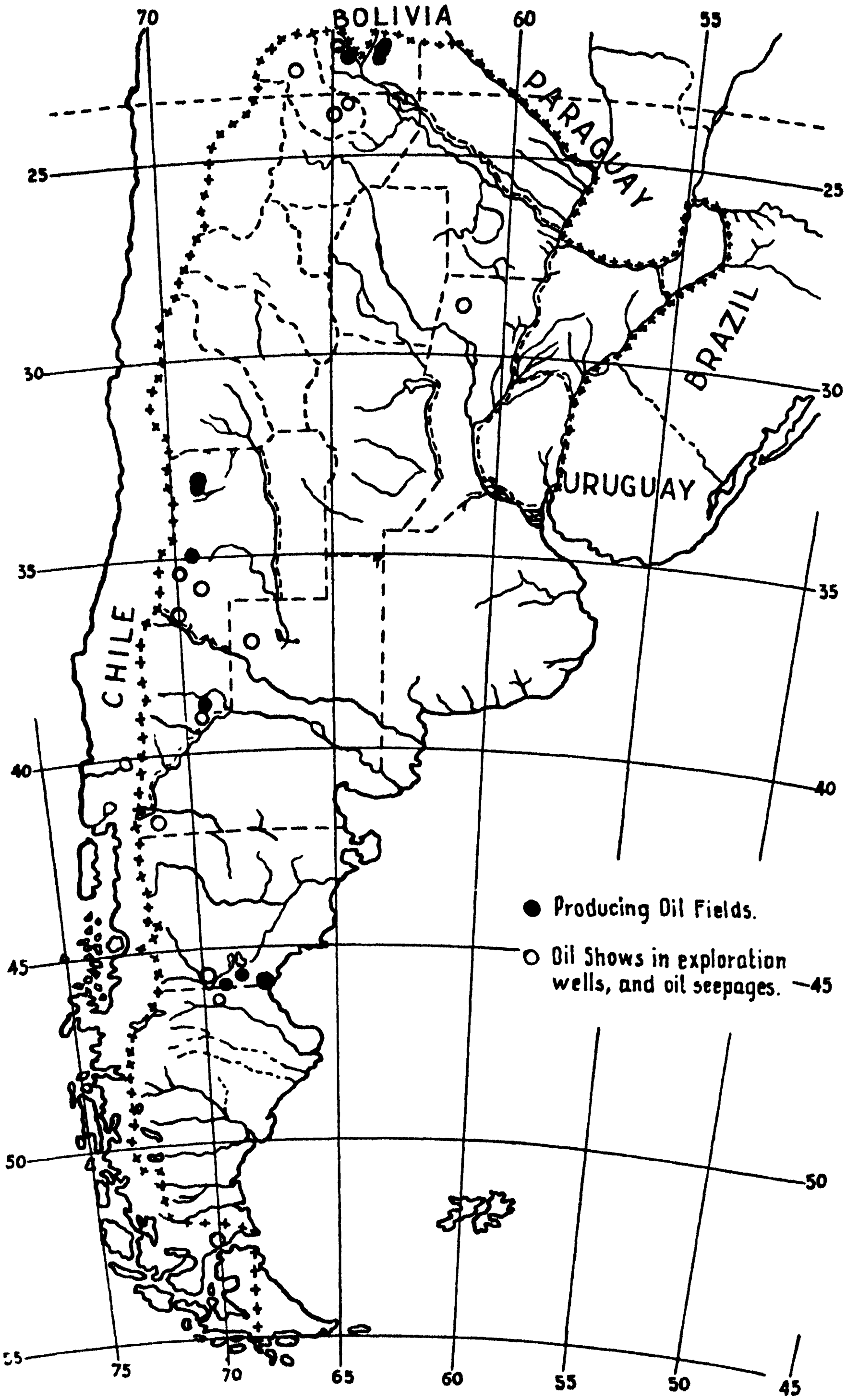

FIG. 2.

Triassic, continental: light oil-shows found in the wells of San Cristobal.

Triassic, continental, and *Permian*, continental and partly glacial: main productive horizons in the oilfields of Salta province.

It is apparent that in the Argentine oil is found chiefly in continental beds. In the oilfield of Cacheuta and in its surroundings no marine formation is known; the Rhaetic bituminous shales with *Estheria*, considered as the probable source rock, may have been deposited in a desert lake or in a coastal lagoon, whose salinity approached or even exceeded that of the oceans.

In the oil-bearing continental formations of Comodoro Rivadavia and Plaza Huincul, petrographers have found a few horizons with dwarf *Foraminifera* which seem to indicate estuarine conditions.

In the small Cerro Alquitrán oilfield, oil accumulations are intimately associated with intrusive magmatic bodies (andesite, supposed of Early Tertiary age). Also in several other regions (La Pampa, Rio Negro, Chubut, and Santa Cruz) accumulations or indications of petroleum have been found very near to intrusive magmatic masses, dykes, and sills.

The stratigraphical sequence is often difficult to determine because of the vertical uniformity and the horizontal variability so common in continental formations. Another common feature, cross-bedding, not infrequently obscures the true attitude of the strata, so that it can be, and has been, a serious source of error.

There are large gaps in the stratigraphical sequence and, therefore, there are many unconformities and disconformities; these render especially difficult the work of the petroleum geologists in the Plaza Huincul oilfield, where there are at least three marked unconformities between the surface of the ground and the oil-bearing beds.

IV. Lithological

In the oilfields of the Argentine, limestones are very poorly developed and volcanic tuffs are very abundant; sometimes these tuffs have been altered to bentonites, but almost always they behave physically as shales.

Sands are mostly medium or fine-grained, often somewhat clayey; in some oilfields the reservoir rock is a rather well cemented sandstone.

V. Structural

Simple anticlines or simple domes: the writer knows of no example of these among the Argentine petroliferous structures. Certain assumptions of simple folded structures, made at an early stage of the development of the oilfields of Salta and Chubut, have since proved to be

erroneous as a result of more information obtained by drilling.

Faulted anticlines: all the producing oilfields of the province of Salta; the anticlines of Tupungato, Ñirihuau, Pampa Maria Santísima, &c.

Faulted monoclines: Cacheuta oilfield; surroundings of the Barda Baya de Puelén.

Faulted tabular structures: Comodoro Rivadavia oilfield.

Complex structures with magmatic intrusives: Cerro Alquitrán oilfield.

Complex structures with buried hills: Plaza Huincul oilfield.

Obscure tectonic conditions, probably related to faults bounding a tectonic trough: Garrapatal.

VI. Production

From 1887 to date more than 4,000 wells have been drilled for oil in the Argentine; the proportion of dry holes has been very low, but few wells have yielded a high initial production, say, of more than 500 bbl. a day even at the commencement. On the other hand, several wells of moderate initial production have had rather long lives, so that their total production has been satisfactory.

In the province of Salta development began in 1925; at the end of 1934 there were 258 holes drilled, with a total production of about 6,150,000 bbl.; production for the year 1934 was a little more than 2,000,000 bbl.

In the province of Mendoza production began in 1887, but data were not available until 1926; the production from 1926 to 1934 was nearly 200,000 bbl.; production for 1934 was about 53,000 bbl., and the total number of wells drilled was more than 60.

In the territory of Neuquén 450 wells had been drilled up to 1934, and the total production from 1918 to 1934 was about 10,000,000 bbl.; production for the year 1934 was a little more than 1,000,000 bbl.

In the territory of Chubut the number of holes drilled between 1907 and 1934 exceeded 3,100, and the total production for this period was nearly 106,000,000 bbl.; the production for the year 1934 approached 11,000,000 bbl.

Up to the end of 1934 the total production of the Argentine oilfields had exceeded 120,000,000 bbl.

Oil-producing Companies.

Dirección General de Yacimientos Petrolíferos Fiscales (Argentine Government Oilfields, locally known as 'Y.P.F.'), in Salta, Mendoza, Neuquén, and Chubut.

Standard Oil Company of Argentine and its subsidiaries: in Salta and Neuquén.

Astra: in Neuquén and Chubut.
Rio Atuel Company: in southern Mendoza.
Diadema Argentina: in Chubut.
Compañía Ferrocarrilera: in Chubut.
Compañía Industrial y Comercial: in Chubut.
Compañía Solano: in Chubut.

Exploration in search of Oil.

Dirección General de Y.P.F. Geological and geophysical surveys: in Salta, Jujuy, Mendoza, Neuquén, and Chubut. Geological only: in Tucuman, Catamarca, La Hioja, San Juan, La Pampa, Rio Negro, Chubut, and Santa Cruz. Geophysical only: in Santa Fé; exploratory wells in Salta, Jujuy, Santa Fé, Mendoza, Neuquén, Rio Negro, Chubut, and Santa Cruz.

Oil Companies (so far as is known to the writer). Geological and geophysical surveys in Salta, Jujuy, and Neuquén; geological surveys in Tucuman, Mendoza, Neuquén, Chubut, and Santa Cruz; exploratory wells in Salta, Jujuy, Tucuman, Mendoza, Neuquén, Rio Negro, Chubut, and Santa Cruz.

AUSTRALIA

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THE continental mainland of Australia is roughly elliptical in shape and has an area of 2,948,366 square miles. It lies between 11° and 38° south latitude, and 113° and 154° east longitude, approximately. Tasmania is south of the mainland and embraces an area of 26,215 square miles. New Guinea, the eastern half of which is under the control of the Commonwealth, lies to the north of Australia.

Broadly speaking, the geological structure of Australia is marked by the existence of three 'oldlands' separated by two geosynclines filled with little altered sediments of Later Palaeozoic, Mesozoic, and Tertiary age. Of course, each of these units is composite, geosynclines including minor 'oldland' elements and vice versa. Fig. 1 gives a highly generalized idea of the distribution of these structural elements.

At the time of writing (December 1934) the production of petroleum products in Australia is commercially negligible. The search for oil and gas has been carried on with more or less vigour for some 25 years, and minor discoveries have been made.

The great world belt of alpine folding, along which are found many of the world's oilfields, misses Australia completely. Passing through the Malay Peninsula, Dutch Indies, New Guinea, and New Zealand, it swings round Australia like the grain in a board swings round a knot in the timber.

The Australian Tertiaries are very little disturbed and altered, precluding the possibility of discovery of oilfields of the Californian–Central European–East Indian type on the mainland. This does not, however, in any way lessen the probability of the existence there of other fields of the types met with in the mid-continent region of U.S.A., in Argentina, and in the Ural Mountains.

Since the alpine folding passes through New Guinea and Papua, the possibilities of the discovery of Tertiary fields in those Territories are high.

Tectonically, the mainland of Australia has experienced no considerable orogenic movement since the close of Palaeozoic time, and only in the coastal portions of Queensland has mountain building been noteworthy since early Palaeozoic time. Generally speaking, orogeny has been progressively more recent from south to north and from west to east. In the southern and western regions even pre-Cambrian formations are little mineralized and metamorphosed. In eastern Australia all rocks older than Carboniferous (with some exceptions) are altered and mineralized and do not enter into consideration as potential source or reservoir rocks for oil.

Although in the western half of Australia the latest granitic injections are not newer than earliest Cambrian, and although Proterozoic formations are lithologically and structurally very little altered, the probability of the existence in them of petroleum is very remote. In Elcho Island (136° E., 12° S.) and in some other parts of the Northern Territory inspissated oil has been met with on shore-lines filling joints in Proterozoic sediments. Its autochthonous origin is, however, very unlikely.

Fossiliferous Cambrian sediments, marked by considerable thicknesses of limestone, are widely distributed chiefly in South Australia and the Northern Territory. Earth movement and consequent alteration in South Australia have removed these formations from the category of potential oil producers, and, even in the north, their high geological antiquity leaves room for grave doubts as to the possibility of oil retention, even though, from the points of view of structure, lithology, and organic content, they compare more than favourably with many of the producing formations in other continents.

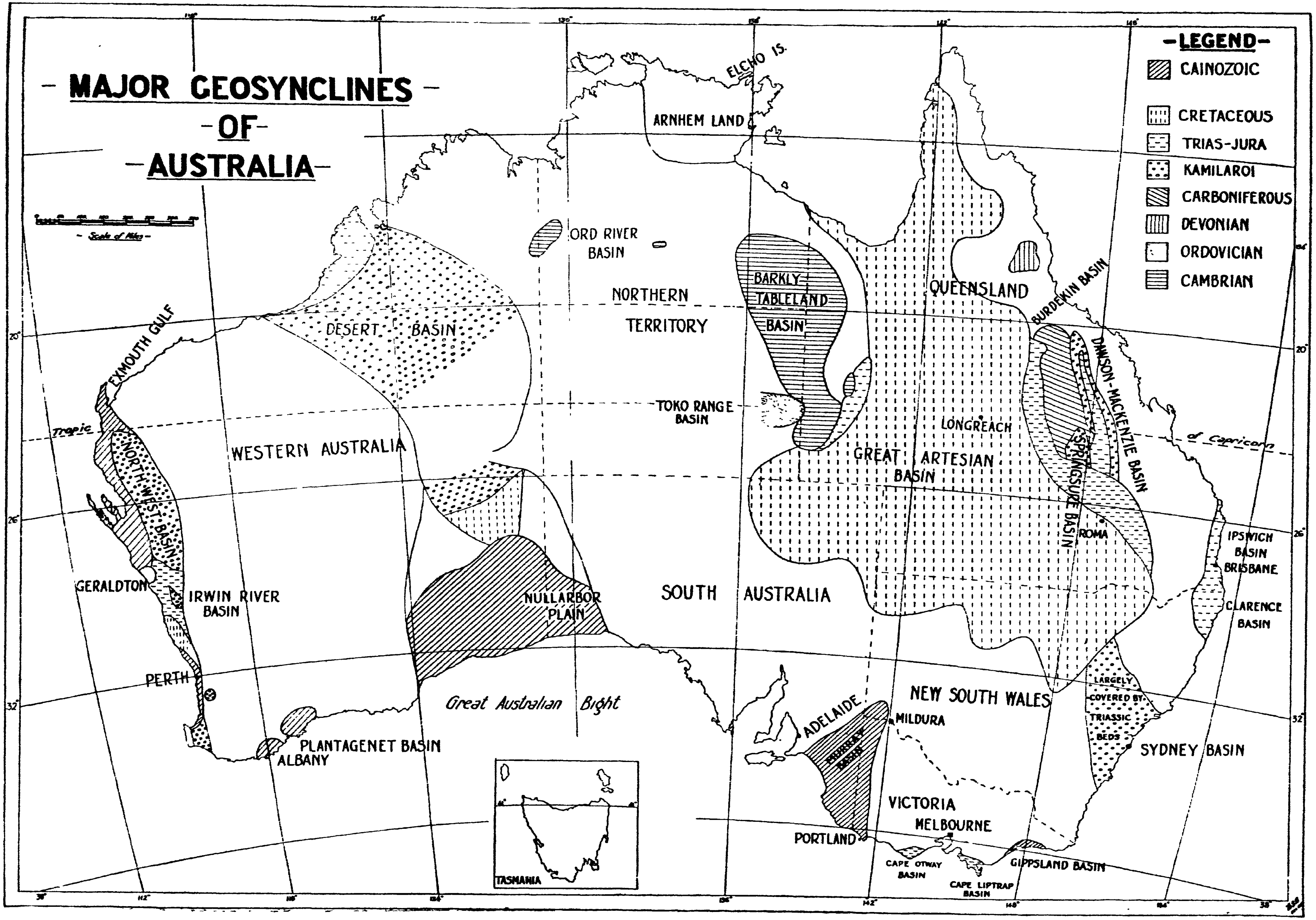
In the Ord River region of Western Australia and the Northern Territory (about 129° E., 17½° S.) there is an extensive Cambrian basin within which the rocks have suffered so little compression as to leave the richly fossiliferous argillaceous members almost unconsolidated. Sub-horizontal Proterozoic sediments containing obscure fossils are overlain by a thick series of basalts, most or all of which appear to have been surface lava flows. The fossiliferous Cambrian sediments rest on these lavas. Along the northern edge of the basin the topmost highly vesicular member of the basalt series has its pores filled with impsonite which has been proved by Simpson to be unquestionably inspissated asphaltic petroleum. Reports of the occurrence of *plastic* bitumen have not been objectively confirmed by submission of samples to official investigation.

A bore sunk in this area failed to bring to light any definite evidence of petroleum. This is not regarded as conclusive negative evidence, since aerial observation suggests that the drilled area was less suitable, by reason of faulting, than it appeared to be from ground survey alone. Reconnaissance aerial observation shows that there exist within the Cambrian geosyncline quite promising gently domed structures. These are worthy of closer investigation, even allowing for the hoary antiquity of the formation.

The origin of the bitumen has been variously explained. Blatchford has suggested that it was formed by distillation from the Proterozoic (or Cambrian) sediments underlying the basalts. Wade and Mahony believe that it is derived from the overlying fossiliferous Cambrian formations. The writer, during a single brief and rudely interrupted visit to the locality, saw at least one dyke or sill intrusive into the Cambrian limestones, and suggests that the very local development of the bitumen has been caused through distillation by a very late and very local basalt intrusion into the limestone material very soon after its deposition.

An enormous development of fossiliferous Cambrian sediments, little affected by earth movement, is met with in the Barkly Tableland of eastern Northern Territory and north-western Queensland (136–9° E., 18–23° S). The region is very sparsely settled and little geological investigation has been carried out. Sub-artesian water has been struck by drilling without any indication of oil coming to light. The age of the formation is against its being petroliferous, but lithologically and structurally it calls for some further investigation.

Ordovician, Silurian, and Devonian formations, widely


- MAJOR GEOSYNCLINES -
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CAINOZOIC
CRETACEOUS
TRIAS-JURA
KAMILAROI
CARBONIFEROUS
DEVONIAN
ORDOVICIAN
CAMBRIAN
ELCHO IS.
ARNHEM LAND
ORD RIVER BASIN
NORTHERN TERRITORY
DESERT BASIN
BARKLY TABLELAND BASIN
QUEENSLAND
BURDEKIN BASIN
DAWSON-MACKENZIE BASIN
SPRINGSURE BASIN
EXMOUTH GULF
TOKO RANGE BASIN
LONGREACH
Tropic of Capricorn
WESTERN AUSTRALIA
GREAT ARTESIAN BASIN
NORTH WEST BASIN
ROMA
IPSWICH BASIN
BRISBANE
GERALDTON
IRWIN RIVER BASIN
NULLARBOR PLAIN
SOUTH AUSTRALIA
CLARENCE BASIN
PERTH
Great Australian Bight
NEW SOUTH WALES
LARGELY COVERED BY TRIASSIC BEDS
ADELAIDE
MILDURA
MURRAY BASIN
PLANTAGENET BASIN
ALBANY
SYDNEY BASIN
VICTORIA
MELBOURNE
PORTLAND
CAPE OTWAY BASIN
CAPE LIPTRAP BASIN
GIPPSLAND BASIN
TASMANIA

developed in eastern Australia, have mostly been extensively metamorphosed and mineralized, constituting the country rocks of the goldfields to a large extent. In the south-eastern corner of the Northern Territory there is known to exist a considerable extent of little disturbed and highly fossiliferous Ordovician formation. While it does not seem very probable that these very old formations are likely to be petroliferous in areas where they have been exposed for long geological periods, the freedom from alteration of the Cambrian and Ordovician formations in the western portion of Queensland may have an important bearing on the presence of oil and gas in the Mesozoic formations which overlap them over vast areas to the east and south-east. Such a condition is closely analogous to the structure of the producing fields of parts of Oklahoma and Texas.

In the Burdekin River Basin of Queensland (145° E., 190° S.) a major development of fossiliferous Devonian beds, although mostly too much indurated and altered for oil development, may repay investigation. Similar rocks must be expected to form part of the basement of the Great Artesian Basin, and, as suggested for the Cambrian and Ordovician, may contribute their quota to the oil indications encountered in the Mesozoic beds there.

Carboniferous formations in eastern Australia are mostly excluded from consideration as potential source beds by reason of their induration and folding.

It is, however, with the Permo-Carboniferous series (Kamilaroi Series) that we encounter conditions which may be regarded as distinctly favourable for oil genesis and retention. Comprising great thicknesses of marine sediments, intercalated with fresh-water coal-measures and, at certain horizons, with glacial formations, the rocks of this system occupy wide and deep geosynclines especially in parts of Western Australia, Queensland, and New South Wales. In many places the edges of these geosynclines are overlapped by fresh-water Mesozoic strata, so that the extent of the potentially petroliferous Kamilaroi system must be regarded as much greater than is indicated by its outcropping positions.

In south-eastern Queensland and north-eastern New South Wales rocks of this age have been considerably folded and mineralized; but usually alteration and contortion are moderate or negligible. Developments of this formation in Tasmania, Victoria, South Australia, and southern Western Australia, though highly interesting and economically important in many ways, may be omitted from detailed consideration in the study of potential oil areas.

The most extensive, and probably at the moment most promising, area of Kamilaroi rocks is that constituting the 'Desert Basin' in north-west Western Australia (121–8° E., 17–23° S.). The bulk of it is entirely unexplored, but some of the most intensive oil search in Australia has been concentrated in its north-eastern corner, along the valley of the Fitzroy River. Numerous bores have been sunk and blebs of bitumen and small amounts of oil have been obtained in several of them, just sufficient to suggest that the formations are definitely petroliferous. Ground surveys and aerial photographic survey have proved the existence of many domal structures, some of them of large dimensions, and it is anticipated that there will be a renewal of active prospecting operations in the near future.

The stratigraphical correlations of the various stages in this region with those in the better known areas of eastern Australia are incomplete. There appear to be a lower limestone series and an upper sandstone series. Most of the drilling has been done, on the cores of domal structures, in the sandstone members. Few adequate cover rocks have been encountered.

A second extensive basin of Kamilaroi rocks in Western Australia occupies portions of the basins of the Lyndon, Minilya, Gascoyne, Wooramel, and Murchison Rivers (114–16° E., 23–8° S.). The region is an arid one, difficult of access, and has not been examined in any detail, for the most part. An area on the Wooramel has been closely surveyed, but appears to be too limited and too much faulted to offer much promise of commercial success. It is noteworthy that a bore sunk here for water yielded brine under a hydrostatic head of about 1,800 ft., pointing to the competence of the cover rocks.

A smaller basin on the Irwin River (116° E., 29° S.) reveals an anticlinal structure, but has not given any evidence of being petroliferous. Here again sub-artesian waters are saline.

All the Western Australian Kamilaroi basins have contemporaneous glacial boulder beds strongly developed.

Kamilaroi formations in the Northern Territory have not been examined at all exhaustively, but do not appear very attractive from the point of view of oil search.

Kamilaroi basins in Queensland are extensive and important. Smaller trough faulted structures like several in Cape York Peninsula, may be neglected for present purposes. Larger geosynclinal areas, however, are of outstanding importance in relation to oil possibilities.

Reid has shown that, east of a line running roughly parallel with the coast, and approximately through the intersection of 151° E. and 26° S., newer Palaeozoic and older Mesozoic formations are considerably compressed and indurated. While it yet remains to be proved, it seems likely that earth movement in this sector has been somewhat too severe to favour retention of oil supplies. West of what may be called 'Reid's Line', earth movement has been much less intense, and lithology and structure are much more favourable than they are farther east.

The whole of south-western Queensland, the north-western part of New South Wales, and a section of north-eastern South Australia are occupied by the geosyncline of the Great Artesian Basin, filled with Mesozoic sediments. On the eastern border of this basin, *and disappearing beneath it*, are some of the most important of the Kamilaroi basins. Special attention may be drawn to the Dawson and Mackenzie River Basin (147–50° E., 21–6° S.) and the Springsure Basin (148° E., 23½–5° S.). In both of these a full suite of marine and fresh-water sediments is developed, richly fossiliferous, and in the former case coal bearing; lithologically they are eminently suitable as source and reservoir rocks for oil. Except in their coal-bearing portions these formations have not been adequately prospected, though they have been geologically surveyed in considerable detail. No seepages or other evidences of the presence of oil have been brought to light in their outcropping portions up to date.

Although crossed by considerable faults, the Springsure area has been shown to possess highly promising domal structures, and test drilling is called for. Of still greater importance, however, is the fact that this anticlinal axis plunges southwards under the mantle of Mesozoic formations in the Great Artesian Basin, and, if continued, must pass not far from Roma (146° E., 29½° S.), where the most outstanding evidences in Australia of gas and oil have been met. There is no reason to deny the probability that similar geosynclines of Kamilaroi sediments form part of

the basement of the Great Artesian Basin in other places, and there is strong presumption that such covered basins, analogous to the deeper structures of Oklahoma and Texas, may be the source of the petroleum definitely recognized in bores in the Great Artesian Basin.

A very extensive and important Kamilaroi geosyncline extends along the New South Wales coast from Port Stephens (152° E., 33° S.) to near Bateman's Bay (150¼° E., 35¾° S.) and back in a general north-north-westerly direction towards Gunnedah (150° E., 31° S.) It certainly extends much farther inland than this, but is hidden beneath Mesozoic formations. This basin includes the productive coalfields of New South Wales, and contains a thick series of glacial, marine, and fresh-water formations. Some slight evidences of natural gas have been encountered, and some drilling for oil and gas has been carried out, so far unsuccessfully. The potentialities of this basin are, however, scarcely yet touched, and much further prospecting is called for.

In eastern Australia the latest Palaeozoic marine transgression occurred about the middle of Kamilaroi (Permo-Carboniferous) time. Upper Kamilaroi sediments are of epicontinental origin, as also are those of Triassic and Jurassic age. Only in Lower Cretaceous time was there a further marine incursion. On the west coast of Western Australia narrow selvages of marine formations of Jurassic and Cretaceous age are encountered, but in the north-eastern portions of that State the Jurassic formations, like those of eastern Australia, appear to be of fresh-water origin.

These fresh-water Mesozoic beds occupy huge geosynclines closely related structurally with those of the preceding era, and the oldlands of Australia were almost or completely isolated from one another by fresh-water seas. One of these occupied the greater part of what is now Queensland, northern New South Wales, and north-eastern South Australia, and in it were deposited the aquifers and cover rocks of the Great Artesian Basin. It is in the *basal* beds of the *fresh-water* Jurassic formation, notably about Roma (146° E., 29½° S.) and Longreach (144° E., 23½° S.) that the most noteworthy discoveries of gas and oil in Australia have occurred. In every instance, so far, the petroliferous products have been encountered in sands either in immediate contact with granitic or metamorphic bedrock, or within a very short distance above the latter. There are very strong reasons for doubting the competence of the Jurassic (locally known as Walloon) beds as mother rocks of oil. The distribution and striking variations in character of the oil and gas encountered, particularly in the Roma district, point strongly, it is believed, to derivation of the hydrocarbons from hidden, truncated domes of Kamilaroi (Permo-Carboniferous) rocks, under conditions closely analogous to those of many of the oilfields of Oklahoma and Texas. So far, drilling has not been sufficiently close to determine conclusively whether accumulation is governed by domal development. The gas and oil sands lie at depths of approximately 4,000 ft., and are overlain by the full thickness of the Walloon Series and by considerable thicknesses of Cretaceous as well in many places. It is not absolutely proved that there is complete conformity between these two formations, though this is generally regarded as being so. Superficial rock decomposition is profound and complete, and geological survey is greatly hampered in consequence. Recently the discovery of a small closed structure east of Roma (Warooby Creek) was followed by drilling and the development of a gas well, pointing to anticlinal control. In some parts of the region, as about Longreach, it has been demonstrated that aerial photographic survey is capable of yielding structural information completely unobtainable by ordinary geological survey methods.

As mentioned above, Kamilaroi rocks, the probable source rocks, disappear beneath the eastern edge of this basin. On the western side Cambrian and Ordovician formations are similarly situated and are at least as favourable, lithologically and organically, as the older Palaeozoic formations exposed on the flanks of the Arbuckle Mountains of Oklahoma would appear to be. It may be presumed, then, that any favourable structure discovered at the surface within the limits of the Great Artesian Basin is worthy of testing by deep drilling. The lower Mesozoic basins of eastern Australia, including the coal basins of south-eastern Queensland, the Clarence Basin of north-eastern New South Wales, the Sydney Basin of New South Wales, the Cape Otway and Cape Liptrap Basins of Victoria, and considerable developments in Tasmania, being entirely fresh-water in character, are not very attractive, though some rather desultory drilling has been done in some of them. In the Clarence Basin a bore for water at Grafton (153° E., 29¾° S.) encountered a gas flow containing traces of ethane.

The narrow coastal basin of marine Jurassic sediments near Geraldton, Western Australia (115° E., 29° S.), though probably too limited in extent to be attractive, shows gentle doming. Water bores have encountered saline supplies in places, but no systematic oil prospecting has been carried out.

The greatest extension of Cretaceous rocks is in the Great Artesian Basin of Queensland, New South Wales, and South Australia, and their possible relation to the known petroleum indications in that basin has been described above. Near Longreach the superficial Cretaceous beds present evidence of exceedingly unstable shore-line conditions of deposition, richly fossiliferous patches being closely associated with lagoonal lenses containing fossil plant stems encased in pseudomorphs after halite. In one place small amounts of unquestionable, plastic, inspissated oil have been obtained; but, apparently, there is not sufficient bulk of such saliferous Cretaceous formations to yield much promise of oil production in quantity.

The extent and thickness of marine upper Cretaceous formations actually exposed in the coastal portions of Western Australia are limited, and the search for oil in them has not been seriously entertained. It is likely, however, that similar beds have a considerable extension under the Tertiary and Recent formations of the Perth Coastal Plain.

Very recently extended field work in the peninsula west of Exmouth Gulf, Western Australia (114° E., 22° S.), has brought to light an extremely important palaeontological suite extending from Cretaceous to Oligocene; the first time that true Eocene beds have been recognized in Australia. These formations are somewhat folded, dips in the neighbourhood of 30° having been recorded. It is understood that further investigation is being carried out by oil interests, and that testing of the area by drilling is being considered. So far as is known, no seepages or other surface indications have been encountered.

With this exception the marine Tertiary formations of Australia have been exceedingly little disturbed. At most they show very gentle dips, and there is a total absence of the acute alpine folding which characterizes the majority of the oilfields in Tertiary areas.

Three major Tertiary geosynclines occur along the south coast of Australia; the Gippsland basin centring about Bairnsdale (148° E., 38° S.); the Murray basin of South Australia extending from the mouth of the Murray River (139° E., 35½° S.) to Portland (142° E., 38° S.) and sweeping inland beyond Mildura (142° E., 34° S.); and the Nullarbor Plain extending north of the Great Australian Bight from 124° E., 34° S. to 133° E., 32° S., and inland for an unknown distance into the unexplored desert interior probably at least to 127° E., 29° S.

Minor basins are met with near Albany (118° E., 35° S.) (the Plantagenet Basin), and to the north-east of this area.

The Gippsland Basin possesses the distinction of having supplied small amounts of petroleum continuously for over four years from pumping bores situated towards the eastern margin of the basin. This discovery has led to the expenditure of large amounts of money in oil prospecting, with a consequence that no part of Australia has been so intensively drilled nor so systematically examined palaeontologically. Unfortunately the fossiliferous Tertiary formations are almost completely masked by a 'blanket' of Pleistocene sands and gravels which entirely prevent any extensive geological or aerial survey. Geophysical (magnetometric) survey suggested the existence of anomalies within the basin, but scout drilling failed to confirm the promise so given.

The results of such geological work as has been possible, supplemented by the somewhat extensive, though rather sporadic drilling, have shown that there is a general monoclinal structure within the basin, with a nearly uniform south-westerly dip at low angles. Towards the western edge there is a change of facies in the Oligocene and Miocene formations from marine to fresh-water, so that the brown coals which are developed to so spectacular an extent in western Gippsland correspond with the petroliferous series of the eastern basin.

The basin is an artesian one, and the oil encountered has been met with in the basal beds of the Oligocene, where it rests on a granitic bedrock, and in association with artesian water, from which, so far, it has not been possible to effect a separation. In spite, then, of the unequivocal proof of the petroliferous nature of the marine Tertiaries in this region, natural obstacles have prevented the development of a commercial oilfield.

In the Murray Basin of south-eastern South Australia, overlapping into western Victoria, the evidences of the existence of oil are far less convincing than they are in the Gippsland Basin. The formations are, however, of the same general age and nature, and there seems no good reason why they may not be petroliferous. As in the Gippsland Basin, most of the surface is hidden under Pleistocene deposits, and outcrops are too scattered for structural features to be determined by geological survey. West of Mount Gambier, however, aerial reconnaissance shows that the Pleistocene covering is so far removed as to render possible delineation of many of the structural features by aerial photography.

One anticlinal structure within this area, exposed in a railway cutting and mapped on the ground, has been drilled. Although the lowest sand encountered at a depth of 2,013 ft. contained microscopic globules of inspissated bituminous material, drilling was abandoned, and the test cannot be regarded as conclusive. A considerable amount of other drilling has been carried out from time to time, but the results cannot be said to be at all convincing.

Farther inland, where the Melbourne to Adelaide railway line crosses the Ninety Mile Desert, the Tertiary formations of this basin are artesian, and yield much-needed water supplies in abundance. There has been no suggestion of the occurrence of oil indications in any of these artesian bores.

The Nullarbor Plain and Plantagenet Basins have not proved of any importance in the search for oil.

It is unquestionably a fact that, since the colonization of Australia, large and small masses of 'bitumen' varying in consistency from soft sticky oil to hard asphaltic glance have been encountered all along the southern coast lines from about Perth to the west coast of Tasmania. Such masses come ashore still, perhaps more abundantly after storms. When first cast on beaches in a soft 'tacky' condition, the material will just float on sea-water. On exposure it rapidly hardens and darkens, and becomes so heavy as to sink in sea-water. Naturally such material is responsible for the constant recrudescence of 'oil discoveries' even in places where the coast consists of Archaean granites and crystalline schists.

Since similar material is met with on the coasts of Chile and New Zealand, and probably also in Kerguelen Island, an extra-Australian source, probably Antarctic, is suggested.

The onshore drift of the scourings of bilges of oil-carrying and oil-burning ships is responsible for some of the phenomena in places like Perth.

There is also a curious alteration product formed from accumulations of marsupial guano in caves and other protected situations which is recurrently responsible for new 'oil discoveries'.

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NEW GUINEA

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THE island of New Guinea has an area of some 300,000 square miles, a large part of which is geologically little better than *terra incognita.* The main feature is a sinuous central backbone of high mountains, frequently exceeding 10,000 feet in altitude [1, 1929]. These mountains are built up of crystalline rocks, sedimentary rocks of various ages, ranging up to Neogene in the highest peak [3, 1927], and young volcanic rocks. On the southern side the sea lies close to the central range at either end, but in the middle a broad strip of low-lying country extends southwards towards the northern part of Australia. Granite outcrops on the south coast at Mabaduan, and a large part of this southern lowland is probably floored at shallow depth by similar rocks. On the northern side the central range is flanked by a great trough, extending for nearly the whole length of the island (McCluer Gulf to Huon Gulf). To the north of this trough lie a number of more or less isolated mountain masses (Van Rees, Gautier, Cyclops, Torricelli, and Finisterre Mountains), all of which appear to be built up essentially by crystalline rocks.

Attempts have been made to interpret the geological structure of New Guinea in terms of alpine tectonics. These are certainly premature, and probably misleading. From the point of view of the oil-prospector, the most important datum appears to be the fact, that strong orogenetic movement took place late in Palaeogene time, so that Neogene sedimentation was concentrated in a number of distinct basins or foredeeps and ran in normal cycles, beginning with deposition of fine-grained, open-sea, largely planktonic materials and ending with shallow-marine, littoral and lacustrine beds. In late Neogene time a further outburst of orogenetic activity caused compression, folding, and elevation of these sediments, a large part of which erosion has since returned to the sea. The problem for the oil-prospector is to discover areas of adequate size within these basins of Neogene deposition, where deformation has not been too intense and where erosion has not already removed those parts of the sedimentary cycle in which oil and gas could most readily be accumulated and preserved.

In the Dutch section of the island, the most important published account of geological investigation in a potential oil-region is that given by Zwierzijcki [2, 1921], who distinguished the following subdivisions of the Neogene sediments in the coastal belt lying to east, south, and west of the Cyclops Mountains:

5. Brown-coal beds.
4. Fossil horizon.
3. Sandstones.
2. Globigerina marls.
1. Conglomerates.

According to Zwierzijcki [2, 1921; 3, 1927], the whole of the Neogene of the northern coast is intensely folded. The anticlines are generally of small amplitude, and usually show cores of the conglomerate or marl subdivisions, in at least one instance exposing the crystalline rocks of the basement.

Conclusions regarding oil prospects were pessimistic. Only two seepages were found, both on anticlines with steep cores, one consisting of rocks of the sandstone group, the other of globigerina marls. Later exploration, of which no scientific details have been published, appears to have yielded more hopeful results.

In the Australian sector (Papua and the Mandated Territory of New Guinea) oil-prospecting efforts up to 1929 were described in some detail in a comprehensive report by the Anglo-Iranian Oil Company to the Commonwealth Government [4]. The main centres of activity were Aitape, on the northern coast, and Upoia in the south.

Near Aitape the oil-seepage at Matapau led to shallow drilling followed by a brief geological inspection, more drilling, then a regional geological survey which produced results corresponding fairly closely with those recorded by Zwierzijcki in the adjoining Dutch territory. No commercial production has been obtained.

Oil seepages were discovered near Upoia in 1911–12. Geological mapping and drilling were carried on by the Commonwealth Government from 1913 to 1920, when the management of the work was entrusted to the Anglo-Iranian Oil Company. Regional geological investigation showed that the immediate neighbourhood of the seepages was structurally unfavourable for oil-accumulation, but suggested that effort might more profitably be expended on well-defined structures lying to east of the Lakekamu River. Attempts to drill one of these structures (the Popo Anticline) were continued at intervals until 1929, but without success. The final report of the Anglo-Iranian Oil Company's geologists tended to the view that exploration should be directed westwards from Upoia, especially to the region of the Purari River, where an early reconnaissance showed signs of the preservation of strata much higher in the Neogene cycle of deposition.

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THE EAST INDIAN ARCHIPELAGO

By Dr. H. SCHUPPLI

Bataafsche Petroleum Mij.

As shown on the accompanying map, the producing oilfields in the East Indian Archipelago are confined to the following areas:—

1. East Java (Rembang, Surabaya).
2. South Sumatra (Palembang, Djambi).
3. North Sumatra (Atjeh, Langkat).
4. South-east Borneo (Koetei).
5. North-east Borneo (Tarakan).
6. North-west Borneo (Sarawak, Brunei).
7. East Ceram (Boela).

With the exception of the oilfields of Sarawak and Brunei (6), these oil-producing areas are situated in the Dutch East Indies.

The oil-bearing formations of the important producing areas of Java, Sumatra, and Borneo situated in the western part of the archipelago, belong exclusively to the Tertiary. In the eastern part of the archipelago oil indications also occur locally in a Mesozoic (mainly Triassic) Flysch series, and the production of the rather unimportant Boela field (Ceram), obtained from Pliocene sands, is probably genetically connected with this Mesozoic series.

As the Tertiary oil is of paramount importance, the geological history of the Tertiary formations is briefly outlined here.

In the beginning of the Tertiary or during lower Tertiary time a number of geosynclinal basins came into existence along the marginal part of the Asiatic continental block, which had been stabilized by pre-Tertiary orogenesis. During the Tertiary these basins maintained a subsiding tendency of an oscillating character, and thick series of marine, lagoonal, and non-marine sediments were accumulated there. This subsidence seems to have been most pronounced during the Miocene, when deposits, partly bathyal and of particularly great thickness, were formed, followed in Pliocene time by a predominantly near-shore and continental sequence, representing the final filling up of these basins.

The total thickness of the Tertiary deposits ranges between 6,000 and 10,000 metres in the central parts of the oil-bearing basins of Sumatra. In the various basins of Java and Borneo the figures are even higher, ranging around or exceeding 10,000 metres.

The main folding of these basins occurred in Plio-Pleistocene time as far as Java, Sumatra, and southern Borneo are concerned. It took place somewhat earlier, i.e. at the end of the Miocene, in the northern part of Borneo (Sarawak and Tarakan basin), followed by less important Plio-Pleistocene movements.

Generally speaking, the primary richness of the oil-bearing series in the East Indian Archipelago does not seem to have been particularly great, at least compared with the oil basins of California, Trinidad, Roumania, for example. This must be concluded from the fact that only anticlines with very favourable conditions as regards structure, size of collecting area, &c., yield oil accumulations of economic importance.

Production is confined to sands and sandstones of Miocene and Pliocene age. The Miocene is by far the most important oil-producing series for all basins, with the exception of Tarakan, where most of the oil is derived from Pliocene beds.

The producing structures are, as a rule, confined to the regions of weak to moderately strong folding. Steeply folded and complicated anticlines, even when situated in areas of favourable facies and rich in oil indications, generally have not yielded paying production. Many of the best oilfields are on asymmetric structures, one flank being flat, the other steep, or even overturned. Sometimes slight thrusting is associated with these steep and overturned flanks.

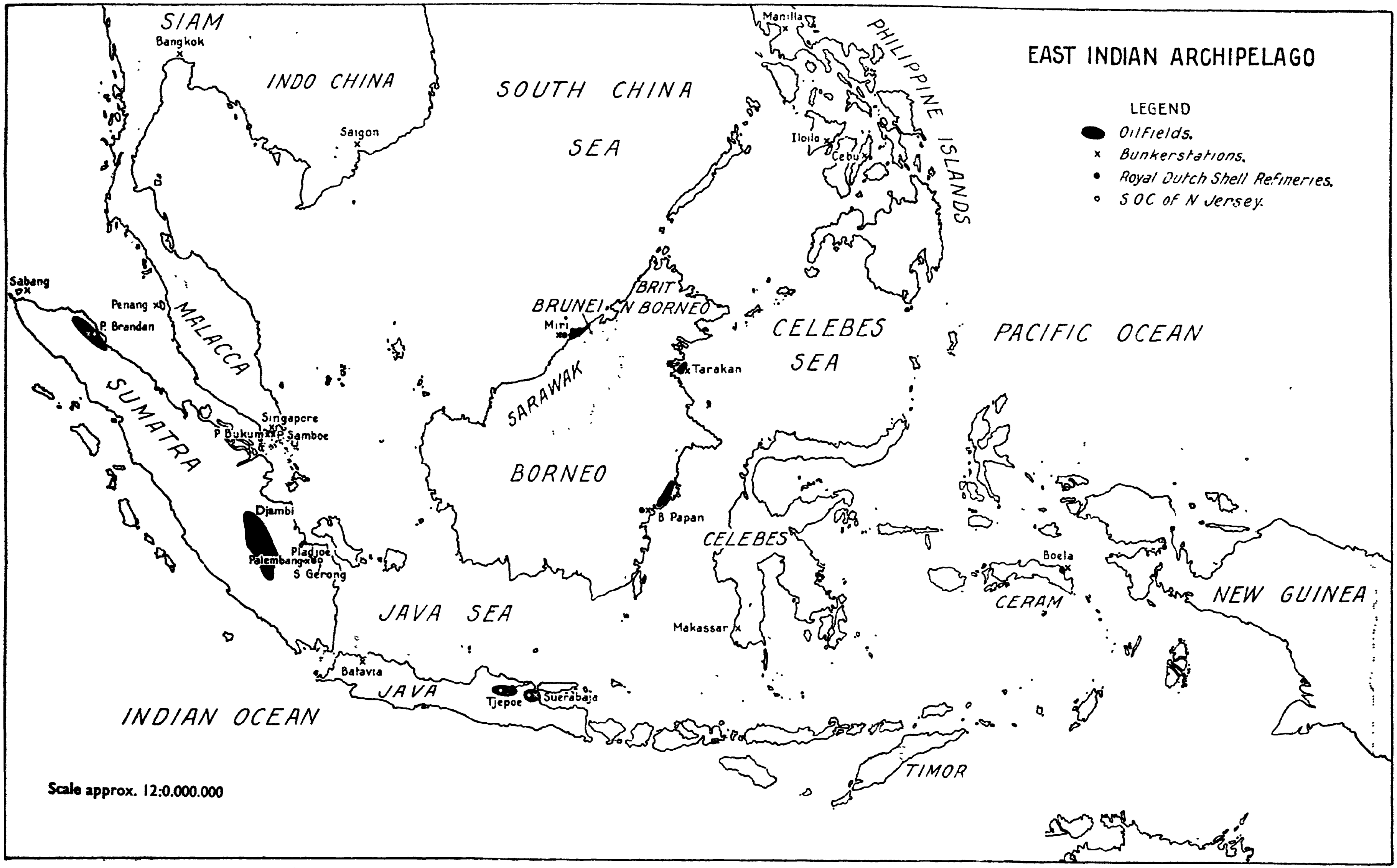
The depths of the producing sands exploited up to now are relatively shallow. In most of the oilfields they range from 500 to 1,000 metres, whilst depths exceeding 1,500 metres are exceptional.

The importance of the individual oil-producing areas may be seen from the following list giving the respective productions during the last 10 years:

The figures in parentheses represent the share of the total production which was obtained by the Koloniale Petroleum Maatschappij, a subsidiary of the Standard Oil Company of New Jersey, which holds some very important fields in South Sumatra and obtains a small production from East Java. All other production belongs to subsidiaries of the Royal Dutch Shell Group.

Crude Oil Production of the East Indian Archipelago in tons of 1,000 kg.

Years	*East Java*	*South Sumatra*	*North Sumatra*	*SE. Borneo*	*NE. Borneo*	*NW. Borneo*	*Ceram*
1925	228,000	418,000	151,000	1,241,000	928,000	613,000	43,000
1926	208,000	550,000	173,000	1,102,000	877,000	712,000	41,000
1927	282,000	704,000	143,000	1,221,000	1,227,000	712,000	37,000
1928	468,000	881,000	158,000	1,348,000	1,304,000	751,000	40,000
1929	635,000	1,259,000	370,000	1,622,000	1,172,000	760,000	45,000
1930	566,000	1,655,000	521,000	1,563,000	1,064,000	702,000	48,000
1931	526,000	1,517,000	460,000	1,307,000	737,000	535,000	42,000
1932	491,000	1,862,000	538,000	1,198,000	838,000	527,000	42,000
1933	467,000	2,175,000	730,000	1,221,000	785,000	623,000	38,000
1934	490,000	2,464,000	1,001,000	1,094,000	821,000	674,000	37,000
1935	505,000	*c.* 2,700,000	889,000	1,009,000	817,000	729,000	42,000
Total prod. from 1925 to 1935	4,866,000	16,185,000	5,134,000	13,926,000	10,570,000	7,338,000	455,000
	(127,000)	(*c.* 7,350,000)					



EAST INDIAN ARCHIPELAGO
LEGEND
Oilfields.
Bunkerstations.
Royal Dutch Shell Refineries.
S OC of N Jersey.
SIAM
Bangkok
INDO CHINA
Saigon
SOUTH CHINA SEA
Manilla
PHILIPPINE ISLANDS
Iloilo
Cebu
Sabang
Penang
P. Brandan
MALACCA
SUMATRA
Singapore
P Bukum
P. Samboe
Djambi
Pladjoe
Palembang
S Gerong
BRUNEI
BRIT N BORNEO
Miri
SARAWAK
BORNEO
Tarakan
B Papan
CELEBES SEA
PACIFIC OCEAN
CELEBES
Makassar
Boela
CERAM
NEW GUINEA
JAVA SEA
Batavia
JAVA
Tjepoe
Suerabaja
INDIAN OCEAN
TIMOR
Scale approx. 12:0.000.000

BURMA AND ASSAM

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I. Distribution of Petroleum in Burma and Assam

THE oil-bearing region of Burma and Assam lies in the angle between the Eastern Himalaya on the north and the Shan Plateau on the east, and is divided into two parts by a group of hill ranges which include the Arakan Yoma, Chin Hills, and Naga Hills. This group of hills divides the main portion of Burma from the Arakan–Bengal–Assam region, and separates two geological provinces.

There are five areas in which oil seepages are numerous: on the eastern side of the Arakan Yoma–Chin Hills ranges are a very large number of oil-shows in the Thayetmo, Minbu, Magwe, and Pakkoku Districts (this area including the main oilfields belt and the foot-hills of the Arakan Yoma), and farther north are the Indaw oilfield and neighbouring oil-shows of the Chindwin Valley and Shwebo District; on the western and north-western side of the hills are the Arakan oil-shows in the south, those of the Surma Valley some 300 miles to the north, and the Assam Valley seepages with the Digboi oilfield rather more than 300 miles north-east.

Gas occurrences are common throughout the region of the oil-shows and many gas seepages associated with saline springs occur to the south of the oil-shows in the Prome and Henzada Districts of Burma. There are also gas seepages and salt springs in the Chittagong District, the Chittagong Hill Tracts, and Hill Tippera (Tripura), linking up the Arakan and Surma Valley shows.

Throughout this note, as far as possible, places are mentioned in geographical order from south to north.

II. General Geology

A. Stratigraphy.

All the known oil-shows occur in Tertiary rocks, which both in Burma and Assam attain an immense thickness.

Pre-Tertiary rocks of various ages make up the greater part of the Eastern Himalaya on the north of the oil-bearing region and occupy a large area to the east of the Irrawaddy, Chindwin, and Sittang Valleys. The Arakan Yoma and Chin Hills, between the two main oil-bearing regions, also include a considerable breadth of pre-Tertiary rocks, mainly metamorphosed argillaceous sediments with ultra-basic intrusions.

Burma Tertiary Stratigraphy. The Burma Tertiaries are divisible as follows:—

Mio-Pliocene	Irrawaddy Series Unconformity	Up to 10,000 ft.
Miocene	Pegu Series (Upper Part) Unconformity	„ 10,000 „
Oligocene	Pegu Series (Lower Part)	„ 10,000 „
Eocene	. . . . . .	Probably 30,000 „

The Lower Eocene beds include a very thick argillaceous group, the Laungshe Shales, which, however, is associated, particularly in the lower part, with sandstones and conglomerates. This is overlain by the Tilin Sandstones, the Tabyin Clays, the Pondaung Sandstones, and the Yaw Stage. The argillaceous Yaw Stage has a rich fauna of Upper Eocene age and includes a variety of rocks, amongst which are carbonaceous shales and coal seams. The Oligocene beds are alternations of sandstones and shales; in the upper part grits and conglomeratic sandstones are common and indicate the early stages of an unconformity which is more pronounced in Assam than in Burma. The Miocene beds are, in general, very similar to the Oligocene, but contain characteristic fossils of Lower and Middle Miocene age. The uppermost Pegu beds are frequently missing owing to the unconformity between the Pegus and the Irrawaddies.

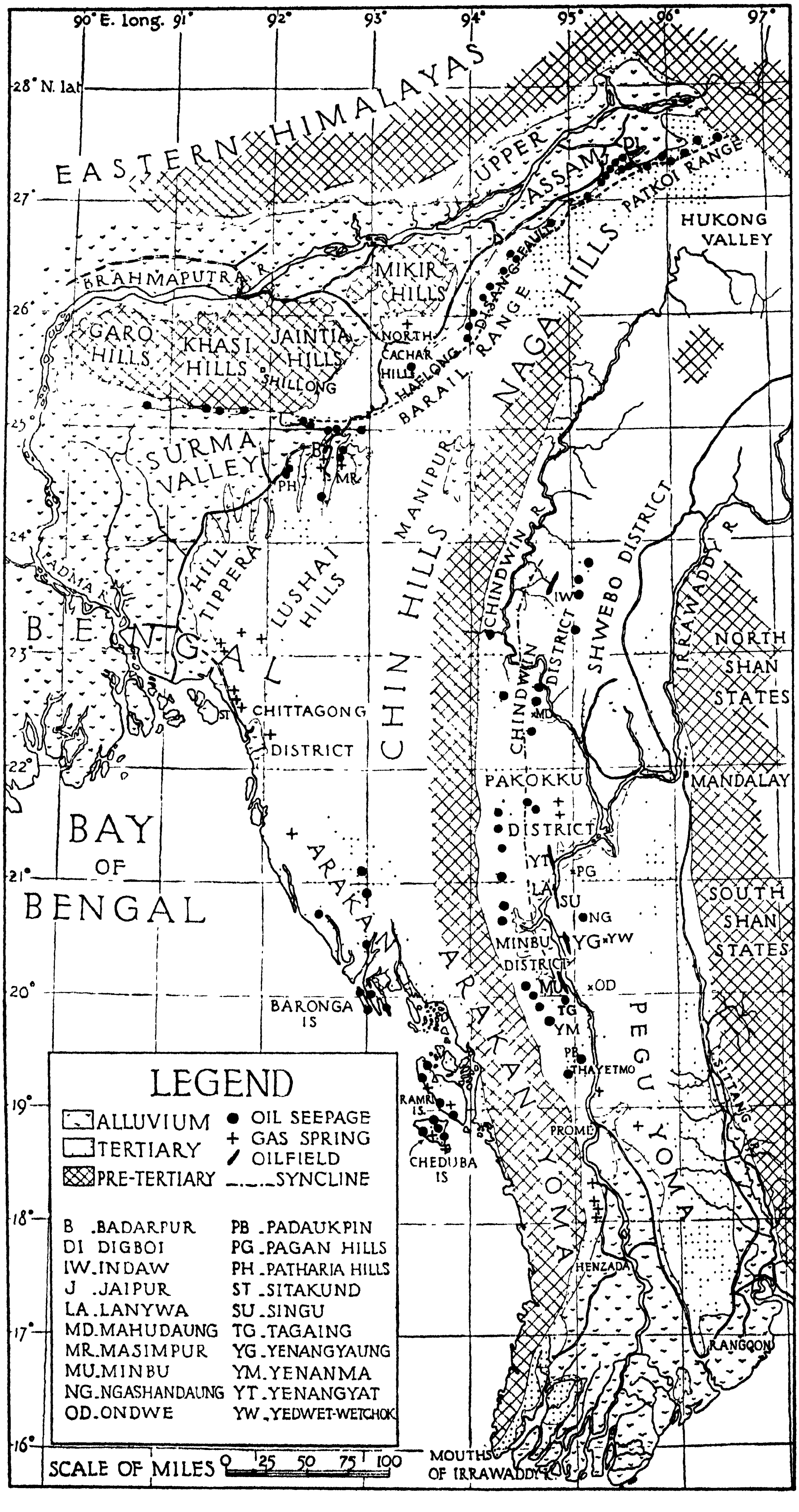
The Pegu succession has been described in several publications of the Geological Survey of India and by Dr. Stamp. Dr. Stamp considers that in a broad way the palaeontological stages cross the lithological divisions, a lithological division in the south being younger than the corresponding lithological division farther north, but this view is at variance with the evidence obtained by the Burmah Oil Company's geologists. Their mapping suggests that as each member of the Pegu succession is traced northwards, it passes from a marine to a non-marine facies, and that lithological units do not show any marked transgression of palaeontological divisions. In the more southerly outcrops the Pegu series contains a large number of marine fossils, but north of the main oilfields area fossils are less abundant, and brackish water forms appear, marine fossils being very rare.

The Pegu beds are overlain by a great thickness of continental deposits, the Irrawaddy Series—mainly yellow and white grits, sandstones, quartz pebble conglomerates, and subordinate, brightly coloured clays. Fossil remains of terrestrial and aquatic vertebrates have been found. The unconformity is often marked by a reddish-brown earthy layer which may rest on any horizon from the Eocene to high in the Miocene.

Arakan–Assam Tertiary Stratigraphy. The subdivisions characteristic of the Tertiaries of the main Burma area cannot be recognized either in the Arakan region of Burma or farther north in Assam. It is evident that conditions of deposition were somewhat different on the two sides of the Arakan Yoma–Naga Hills ranges, and the paucity of fossil remains makes it very difficult to correlate the Assam succession with other areas. A local classification of the Assam rocks has recently been extended to include the Arakan region of Burma; the main divisions are given in the following table, but it is necessary to emphasize that the ages indicated for the Assam and Arakan rocks are at present to be regarded as tentative suggestions.

Mio-Pliocene	Dihing Series	Up to 5,000 ft.
Probable unconformity		
Miocene	Tipam Series and Surma Series	„ 25,000 „
Important unconformity		
Eocene to Oligocene	Barail Series	15,000 „
Eocene	Jaintia Series	2,000 „
	and Disang Series	Over 10,000 „

The lowest Tertiary beds of Assam, the Disang Series, are mainly dark-grey splintery shales. These are thought to be



90° E. long. 91° 92° 93° 94° 95° 96° 97°
28° N. lat
27°
26°
25°
24°
23°
22°
21°
20°
19°
18°
17°
16°
EASTERN HIMALAYAS
UPPER ASSAM
DI
PATKOI RANGE
HUKONG VALLEY
BRAHMAPUTRA R.
MIKIR HILLS
DISANG FAULT
NAGA HILLS
BARAIL RANGE
GARO HILLS
KHASI HILLS
JAINTIA HILLS
SHILLONG
NORTH CACHAR HILLS
HAFLONG
SURMA VALLEY
B
J
PH
MR
MANIPUR
HILL TIPPERA
LUSHAI HILLS
CHIN HILLS
PADMA R.
BENGAL
ST
CHITTAGONG DISTRICT
CHINDWIN R.
CHINDWIN DISTRICT
IW
SHWEBO DISTRICT
MD
IRRAWADDY R.
NORTH SHAN STATES
MANDALAY
PAKOKKU DISTRICT
YT
PG
LA
SU
NG
YG
YW
MINBU DISTRICT
MU
OD
TG
YM
PB
THAYETMO
PEGU YOMA
SOUTH SHAN STATES
BAY OF BENGAL
ARAKAN
ARAKAN YOMA
BARONGA IS
RAMRI IS.
CHEDUBA IS
PROME
HENZADA
SITTANG R.
RANGOON
LEGEND
ALLUVIUM
TERTIARY
PRE-TERTIARY
OIL SEEPAGE
GAS SPRING
OILFIELD
SYNCLINE
B .BADARPUR
DI DIGBOI
IW.INDAW
J .JAIPUR
LA.LANYWA
MD.MAHUDAUNG
MR.MASIMPUR
MU.MINBU
NG.NGASHANDAUNG
OD.ONDWE
PB .PADAUKPIN
PG .PAGAN HILLS
PH .PATHARIA HILLS
ST .SITAKUND
SU .SINGU
TG .TAGAING
YG .YENANGYAUNG
YM.YENANMA
YT .YENANGYAT
YW .YEDWET-WETCHOK
SCALE OF MILES 0 25 50 75 100
MOUTHS OF IRRAWADDY R.

equivalent to the Laungshe shales of Burma, but may include some Cretaceous beds. In the north-western part of Assam (Garo Hills to Mikir Hills) the Disang Series is not found and its place in the succession is taken by the Jaintia Series, which includes fossiliferous limestones and is of Middle or Lower Eocene age. The Barail Series includes sandstones, shales, and carbonaceous shales, and in the extreme north-east of Assam is marked by a development of thick coals near the top of the series; these may possibly be correlated with the Yaw Stage of Burma, but fossils are extremely rare and badly preserved.

The unconformity which separates the Eocene-Oligocene succession from the Miocene has resulted in the complete removal of the Barail Series in some parts of Assam; in other localities the Surma Series is missing, and the Tipam beds rest directly on the Barails. The Surma Series consists of impure shales and sandstones with frequent ferruginous conglomerates; a few fossils occur which show the series to include beds of Lower Miocene age. This series is very poorly developed in Upper Assam, is well developed throughout the Surma Valley, and reaches a very great thickness in the Arakan coastal region of Burma, where the rocks are rather finer in grain. The overlying Tipam Series includes ferruginous sandstones and, in the north, mottled clays; fossils are very rare, except in Arakan, and there is some doubt about the age of the series as some fossils have been thought to suggest the presence of Upper Miocene or even Pliocene beds. Different views have been expressed regarding the correlation of the Tipam Series with the Burma succession; the apparently conformable passage from the Surma Series into the Tipam Series and the unconformity believed to occur above the Tipam Series make it probable that this series does represent the uppermost part of the Pegu succession, but this tentative correlation must await confirmation or revision. The highest Tertiaries of Assam, the Dihing Series, are pebble beds which appear to be equivalent to some part of the Irrawaddies of Burma.

B. Structure.

From the remarks in the opening paragraphs it will be appreciated that the Tertiary beds of Burma and Assam lie in two large geosynclines, one stretching from the Arakan Coast of Burma northwards through the Surma Valley into Upper Assam, and the other occupying the Irrawaddy–Chindwin Valley of Burma. Throughout the two regions the general lines of folding are roughly parallel to the boundaries of the main synclinal areas, and a large part of the Tertiary tract has been thrown into a series of long narrow folds which in many places have been severely overthrust. There are naturally occasional divergences from the general trend of folding, and small areas, such as the North Cachar Hills in Assam, and especially the synclinal tracts, show fairly broad stretches of nearly horizontal beds. The overthrusting is possibly most strongly developed in the Naga Hills ranges to the south-east of the Upper Assam Valley. The principal overthrust fault of this area is known as the Haflong–Disand fault, and this forms a structural line which has been traced for 400 miles.

III. Stratigraphical Distribution of Petroleum

In Burma oil seepages occur throughout the range Upper Eocene to Middle Miocene. Gas and salt-water springs and mud volcanoes are also numerous, being associated with beds ranging from Middle Eocene to Miocene. In the Yenangyaung oilfield the principal production has come from Upper Oligocene and Lower Miocene sands. Some lower horizons are productive in the Minbu group of fields, and the production of the Singu–Lanywa–Yenangyat fields comes from the Oligocene, the Miocene beds being exposed.

In the Arakan–Assam geosynclinal tract oil seepages range from Eocene to high in the Miocene, being prominently associated with the upper part of the Barail Series and the lower part of the Surma Series, but in Upper Assam extending into the Tipam Series. Mud volcanoes, gas-shows, and saline springs are numerous, both in the highest Barail beds and in the Surma beds. Oil indications are thus very closely connected with the Oligocene unconformity.

IV. Structural Distribution of Petroleum

In Burma most of the oilfields lie on the eastern rim of the main synclinal tract which runs roughly along the line of the Irrawaddy–Chindwin valley. To the south of this elongated basin are the Pyaye dome with gas, and the small Padaukpin field. Farther north, and on the western side of the main axis, is the small oilfield of Yenanma. On the eastern side of the syncline is the northerly pitching Tagaing structure which had a short-lived production. Northwards come the central oilfields; Petpi, Yethaya, Palanyon, and Minbu form the southernmost group (Minbu line of folds), then 20 miles to the north is Yenangyaung, and 30 miles farther north is the group which includes Singu, Lanywa, Yenangyat, and Sabe. All these fields of the central region lie immediately east of the axis of the main geosyncline. The only other oilfield is at Indaw, situated about 150 miles farther north, and also lying just east of the main axis. Although there are many other folds in the oil belt, production on a commercial scale has been obtained only from those anticlines which lie along the edge of the main synclinal area.

In the Arakan–Assam region there is no main structural synclinal line closely corresponding to the Irrawaddy–Chindwin geosyncline of Burma. There is presumably a major synclinal axis beneath the Bay of Bengal, with the seepages and mud volcanoes of the islands of the Burma coast (Cheduba, Ramri, Baronga) to the east of it. This axis probably continues northwards under the Bengal alluvium and swings north-eastwards into the Surma Valley, at the head of which are many oil-shows. The Badarpur field, which has given a small production of oil, lies in this area. The synclinal axis pitches out in an east-north-easterly direction in the Naga Hills. In Upper Assam there is another major synclinal axis somewhere beneath the Dhansiri–Brahmaputra alluvium, and the Digboi field lies near the north-eastern end of this syncline on what is probably the first fold to the south-east. The numerous seepages of the Naga Hills occur on the south-eastern side of the Upper Assam syncline.

Structure of the Oilfields.

All the oilfields of importance in Burma and Assam and many of the seepages lie on anticlinal folds. The seepages of the 'western outcrops' of Burma and the 'northern outcrops' of the Surma Valley are exceptions; so, too, is the small accumulation of oil in the Yenanma field where the structure is apparently monoclinal. The Minbu line of folding is rather sharp, the eastern flank being the steeper. The small dome of the Yethaya field is close to, but east of, the main Minbu line of folding. The Yenangyaung field

is a comparatively gentle elongated dome, slightly asymmetrical; the eastern flank is more gentle, and drilling in recent years has led to an eastward extension of the productive area. The Singu and Lanywa oilfields lie on a markedly asymmetric fold which, like the Minbu line of folding, has a steep eastern flank. Almost on the same line is the Yenangyat–Sabe flexure which is similarly very strongly asymmetric. The isolated Indaw field is on an elongated dome.

On the western side of the Arakan Yomas the seepages are associated with compressed folds; very small productions have been obtained from shallow wells drilled near seepages in Ramri Island and in Eastern Baronga Island. Farther north the oil- and gas-shows of the south-eastern side of the Surma Valley are all on asymmetric, often overthrust, anticlines. The Badarpur structure is a small dome with an overthrust eastern flank. In Upper Assam most of the oil-shows occur along or in close association with the strike-faults which are such a distinctive feature of the Naga Hills structure. Near Digboi the overthrusting is less severe, and the Digboi oilfield is situated on a sharp asymmetrical fold with a steep and faulted northern flank.

V. Origin of Oil in Burma and Assam

The conditions favourable for the formation of oil persisted from the Middle Eocene to the Middle Miocene. In Burma the deposition appears to have been in a gulf into which sediment was carried mainly from the north, but also from the east and west. From the facies of the Pegu strata outcropping round the edges of the main synclinal basin and from numerous cores of the strata of the oilfields it is inferred that the bulk of the sediments in the broad synclinal area are of shallow marine facies. During late Oligocene times there appear to have been considerable local interruptions in sedimentation.

In Assam there is an intimate association between the occurrence of oil-shows and the Oligocene unconformity. Oil is also closely associated with the coal-bearing beds in north-eastern Assam and with the Tipam beds, whose lithology there suggests a definitely non-marine type of deposition. Since the Tipams are petroliferous only where they rest on petroliferous Barail beds, and in view of the intimate connexion between the coal-bearing beds and the oil sands, it seems likely that extensive migration has taken place, presumably from the geosynclinal area beneath the Brahmaputra alluvium.

VI. Bibliography

The most important source of information regarding the Burma and Assam Oilfields for the period prior to 1912 is Dr. Pascoe's memoir (*Mem. Geol. Surv. Ind.* **40,** parts i and ii (1912, 1914)). Later references to Burma are to be found in the Geological Survey Records and in other publications; a full list is included in Dr. H. L. Chibber's *Geology of Burma* (Macmillan, 1934). The occurrence of oil in Burma has been discussed in several papers by Dr. Dudley Stamp: 'The Conditions governing the Occurrence of Oil in Burma' (*J. I.P.T.* **13,** 21 (1927)), 'The Connection between Major Structural Features and Commercial Oil Deposits' (ibid. **14,** 28 (1928)), and 'The Oilfields of Burma' (ibid. **15,** 300 (1929)). These papers also contain a bibliography.

The most recent discussions of the oil distribution of Burma are contained in the paper by G. W. Lepper published in *Proc. World Petr. Cong.* **1,** 15 (1933), in Dr. Chibber's book referred to above, and in a contribution by Dr. Stamp to Dr. Chibber's *Mineral Resources of Burma* (Macmillan, 1934) in which he summarizes his earlier papers.

There has been very little published on the oil geology of Assam since Dr. Pascoe's memoir, but the general stratigraphy is given in 'Explanatory Notes to accompany a Table showing the Tertiary Succession in Assam' (P. Evans, *Trans. Min. Geol. Inst. Ind.* **27,** 155 (1932)), which contains a full list of references. The distribution of oil is discussed in G. W. Lepper's *World Petroleum Congress* paper.

LANYWA OILFIELD, UPPER BURMA

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THE Singu oilfield is truncated at its northern end by the left bank of the Irrawaddy River and the surface geology indicates a continuance of the fold beneath the river-bed to the right bank where the Singu structure, pitching to the north, appears to lie *en echelon* with and somewhat to the west of the southern end of the Yenangyat anticline. Production from wells on the right bank of the river was obtained by the Indo-Burmah Petroleum Co. Ltd. in 1921, and since that date a portion of the river-bed has been reclaimed by means of a stone and brick-faced embankment, 2 miles in length, and of sufficient height to withstand a seasonal variation in river-level of over 40 ft. The area behind the embankment has been filled to above high-water level by material dredged from the river-bed. Before the filling was complete the wells were surrounded by water for 6 months in the year and all work was carried on from raised platforms connected by bridges.

Oil sands at 1,700, 1,900, and 2,500 ft. have so far been exploited, and additional sands are now known to exist. The structure is regular, and the oil sands show little lateral variation. Throughout the area worked there is a low pitch to the north, which is but little disturbed by cross-faults. Sixty-seven wells had been drilled, and a total production of 3,414,934 bbl. recovered from the Lanywa field to the end of 1935.

NORTH-WEST INDIA

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THE petroleum occurrences of the Punjab and North-West Frontier Province are described by Dr. (now Sir Edwin) Pascoe in *Mem. Geol. Surv. India*, 40, pt. 3 (1920), and a full bibliography to 1919 is given in this work. A later paper by R. Van Vleck Anderson (*Bull. Geol. Soc. Amer.*, 38, 665) contains a detailed description of the geology of the Punjab oil region.

Surface oil-shows are numerous and occur over a wide area from north-east of Rawalpindi to northern Baluchistan. Mud volcanoes occur on the Mekran Coast, 90 miles north-west of Karachi; one of these, Chandragup, is a mud-cone over 300 ft. high. The oil is believed to have originated in Eocene times during alternations of marine and inland sea conditions, and a large proportion of the seepages are associated with gypsiferous marls overlying massive nummultic limestones. The Eocene rocks are overlain unconformably by fresh-water sandstones and shales of Oligocene to Pleistocene age, and a large number of oil-seepages occur at the outcrop of the plane of unconformity; in these cases the oil is believed to reach the surface by migration along the plane of unconformity. E. Parsons (*J. I.P.T.* 12, 439 (1926)) suggests that migration has taken place along fault-planes.

The Eocene and younger rocks have been affected by the orogenic movements of late Tertiary times which gave rise to the Himalayan Mountains and associated ranges. Immediately under the hills the compression has been severe, but away from the hills the folding becomes more open, and it is from anticlines in this structural zone that oil-production has so far been obtained.

The earliest well drilled for oil in the Punjab was put down near Jafar in 1869, and in the early seventies an oil expert, F. W. Lyman, was engaged by the Punjab Government to report on the known oil localities. Borings were put down on his recommendation, but no production was obtained. In 1890 a government-aided syndicate managed by the Townsend brothers carried out prospecting on a considerable scale and a number of wells were put down at Chharat and Jaba in the Attock district, Punjab, at Kundal in the Trans-Indus Salt Range, at Khattan in Baluchistan, and near Sukkur in Sind. Small quantities of oil were obtained from the first four of these localities, and oil from Jaba was used for many years at the Rawalpindi gas-works. In 1912 yet another unsuccessful test was drilled at Golra near Rawalpindi.

The Attock Oil Company commenced drilling at Khaur, 45 miles south-west of Rawalpindi, in 1914, and production was obtained from shallow sands in 1915. A refinery was constructed in Rawalpindi and commenced working in 1922. To the end of 1935, 228 wells had been drilled and a total production of 2,945,448 bbl. recovered from the Khaur oilfield. Oil occurs in fissures in the Murree sandstones from the surface to depths of over 5,000 ft.; and recently oil has been obtained at still greater depths in the Eocene limestone. Fluid conditions have been irregular and drilling has been difficult, due to heaving formations and high-pressure gas and water sands. A special technique was devised to meet these conditions, and this is described in a paper by C. E. Keep and H. L. Ward (*J. I.P.T.* 20, 990 (1934)).

In 1935 oil was discovered by the same company in the Dhulian anticline, 10 miles south-west of Khaur. Oil occurs there in the basal beds of the Murree and in the Eocene limestones at a depth of 7,500 ft.

Unsuccessful test-wells have been drilled by various companies at Kabakki and Gabhir on the Salt Range, Meyal, Jhatla, and Chharat in the Attock district, the Marwat Range, Trans-Indus, on the Sukkur dome, south of Rohri, in Sind, and on the Mekran coast near Chandragup.

CHINA

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A LARGE part of the Chinese Republic consists of rocks of types and ages in which no possibility of commercial oil deposits exists. Some parts of the country, however, have seepages and other surface indications or structures of suitable types in sedimentary basins.

Among the regions where oil is known to exist is the Shensi Basin, situated in northern Shensi Province, touching western Shansi, eastern Kansu, and a bit of Inner Mongolia. The length of this basin is about 450 miles from north to south and 250 miles from east to west, and it therefore contains more than 100,000 square miles of sedimentary rocks of suitable age to hold commercial fields. Anticlines are conspicuous on the borders of the basin, but they become gentler as the centre of the basin is approached, so that the greater part of that vast area is underlain by rather flat to gently dipping strata in which 'closed' structures are rare. The surface sandstones are of various 'Permo-Mesozoic' or Mesozoic ages, whereas underlying shales, sandstones, and limestones range from Carboniferous down to Cambrian.

Oil seepages at Yenchang (Shensi Province) were mentioned more than 200 years ago in the *Ta Min I Tung Chih*, or *Chronicle of the Great Ming Dynasty*. The later *Chronicle of the Great Ming Dynasty* also mentions petroleum, as does the *Fang Yu Chi Yao*, or *Concise Geography* by Ku Chu-yu, the Prefectural Record and District Record of Yenchang. In a geological study of the Province the writer and his associates found and proved sixty-three actual seepages [2, 1926] all of about the same size.

Drilling commenced in April 1907, when an outfit was purchased in Japan by the Imperial Government on the advice of Mr. K. Inami of Wuchang. The first discovery was in October of that year just outside the gates of Yenchang, where an initial yield of 60 bbl. per day was found at a depth of 230 ft. A small refinery was then constructed and is operated to this day, the oil coming also from three wells within a few hundred feet of the original one and from a depth of about 370 ft. No materially abnormal structure exists at the locality except small terrace or ravine-like deviations from the normal westward dip of one or two degrees.

Later test wells were drilled by the Standard Oil Company of New York in conjunction with the Chinese Government at several points in Shensi Province, but little additional oil was found at depth. The following figures are given by Chu [1, 1924] (errors of location corrected).

No.	*Locality*	*Depth, ft.*
1	Yenchang	2,770
2	Yungpingchen, 35 miles NW. of Yenchang	2,000
3	2½ miles NE. of Yenanfu	3,000
4	2 miles SW. of Tientou, district of Chungpu	3,545
5	5 miles SW. of Tientou	2,500
6	13 miles NW of Tungkuan	2,800

In 1917 the oil produced amounted approximately to 2,582 bbl. The last-mentioned well was located on an anticline, No. 5 was on a weak dome, Nos. 3 and 4 on structural terraces, and the first two in proximity to seepages, since suitable anticlines or domes were not known at that time.

Another great structural basin is situated in Szechuan Province, where the central region consists of Carboniferous, Permian, and Mesozoic strata. There is said to be a good anticlinal structure, the lateral dips ranging from two to eight degrees. All the drilling was in search of salt-water, the production and evaporation of which constitutes an extensive industry in western China, just as it did in Pennsylvania before the days of oil discovery there. The following records of groups of wells are given by Chu:

No. of locality	*Name of locality*	*Depth, ft.*
1	Niuhuachi	2,000–2,400
2	Chukantan	1,500–1,710
3	Between Chukantan and Faeshanching	250–1,650
4	Faeshanching	1,400–1,600

More than 1,000 wells have been drilled, about one-fifth of which had some oil and gas. The deepest test holes are said to be about 4,000 ft. deep, and in 1918 about 300 bbl. of oil were obtained from these wells.

Besides the Szechuan and Shensi basins oil seepages are reported in the Lingwu, Chengchen, Kuyuan, and Huating districts of eastern Kansu Province and in Yungchang, Zuechuan, Yumen, and Toukwang districts of western Kansu. Petroleum is also reported in sixty-five springs in Wusu, Kuchu, Suilai, Dihua, and Taecheug districts of Sinkiang Province, but no detailed geological studies have been made and no known prospecting has taken place.

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THE GEOLOGY OF THE OILFIELD BELT OF IRAN AND IRAQ[1]

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I. Introduction

THE oilfield belt of southern and south-western Iran and of Iraq lies within a sector of the Alpine mountain system. The Dinaric limb of this system swings south-eastward through the Balkans and thence in a series of great arcs to the neighbourhood of Alexandretta in Syria. Between this point in Syria and Mosul in Iraq, the dominant strike swings gradually from north-east to south-west through east to west to a north-west to south-east direction. From Mosul to Bandar Abbas at the entrance to the Persian Gulf, a distance of 1,000 miles, the general north-west to south-east strike is maintained and the magnificent mountains of this sector, the Zagros Ranges, as they are called, form the subject of this article. East of Bandar Abbas structural complications set in. One branch of the fold-system swings southward into Oman in south-eastern Arabia, while another branch, of very different structural and stratigraphical composition, continues eastward along the Mekran and Baluchistan coastal zone.

The Zagros Ranges between Mosul and Bandar Abbas show, in general terms, a remarkable uniformity, though naturally differences in detail are numerous. Structurally the ranges form an almost ideal example of a fold-system. The direction of movement was from the north-east towards the south-west, and the intensity of folding shows a gradual diminution in this direction. In the north-east are great overthrusts. The geology of the overthrust zone is not dealt with in this article. For a more complete account of the structural conditions see *The Structure of Asia* (de Böckh [2, 1929]). In front of these lies a belt of tightly packed folds and fault-structures giving an imbricate pattern and exposing Palaeozoic and Early Mesozoic rocks, which form mountain ranges of up to 15,000 ft. in height. This is followed to the south-west by a zone of long regular fold-mountains in which Cretaceous and Palaeogene limestones are the dominant feature-forming rocks. The mountain belt is flanked on the south-west by a foot-hill zone composed almost exclusively of thick Neogene deposits. As the plains are approached the interval between anticlines increases and the broad synclines are filled with Pleistocene and recent alluvial deposits. Finally, the broad synclinal zone occupied by the plains of Iraq and south-western Iran and the Persian Gulf is still, throughout much of its extent, slowly subsiding and being filled by the deposits of the great rivers, the Tigris, the Euphrates, the Karun, and their tributaries.

Stratigraphically, the Zagros Mountains may also be regarded as one large unit and, in general terms, the uniformity of depositional conditions throughout their length is most remarkable; a noteworthy feature is the dominance of limestones or marlstones throughout the sequence from Permian to Palaeogene. (The term marlstone is used to describe a calcareous rock containing up to 40% of argillaceous material which is hard and brittle in its physical character.) Our knowledge of older Palaeozoic rocks is limited to relatively few outcrops; between the Cambrian and the Permian the geological record is scanty, but there are no angular discordances. From the Permian onwards, however, sedimentation was continuous and very uniform over wide areas.

The first orogenic movements of importance occurred in the Upper Cretaceous along the north-easterly margin of the geosynclinal zone. In depressions adjacent to the mountains formed by those movements thick sandstones and conglomerates were deposited during the Maestrichtian and the Lower Eocene, but farther to the south-west uniform marine sedimentation of marlstones and limestones continued without a break.

The dominance of calcareous sedimentation ended with the Lower Miocene and was succeeded by a lagunar phase. Local and temporary concentrations of the sea-water had resulted in some gypsum deposits at intervals throughout the Mesozoic and Early Tertiary, but these are of small importance. During the Early Miocene chemical sedimentation became very widespread and great thicknesses of anhydrite and salt were deposited. This formation, the Lower Fars Series, is of great economic importance, as it provides an excellent impervious cover for the oil-reservoirs in the limestones immediately beneath it. During later Miocene and Pliocene times thick detrital deposits, sandstones and shales, and finally massive conglomerates, formed the concluding phase of the cycle. The orogenic movements which gave their present form to the Zagros Ranges commenced in the Early Miocene and culminated in the Late Pliocene.

II. Stratigraphy

1. Pre-Cambian.

No exposures of pre-Cambrian rocks have been found throughout the autochthonous zone of Iran or Iraq. Crystalline schists and eruptive rocks of granitic character, sometimes gneissic in texture, are known in the zone of nappes, but these may be partly or wholly of Palaeozoic, possibly even Mesozoic age.

2. Palaeozoic.

Palaeozoic strata appear at the surface only in areas of considerable tectonic disturbance, either in faulted anticlines or in salt-plugs. The sequence is thus often obscure or defective, and some of the major divisions have not been recognized. It is fairly certain that, over much of the region, marine sediments assignable to Silurian, Devonian, and all but the uppermost part of the Carboniferous are absent.

(*a*) **Cambrian.** Normal exposures of Cambrian occur at the base of the great fault-slices in the Bakhtiari Mountains and in Kuh-i-Dina. Lower Cambrian consists of chocolate-coloured shales with black and variegated leached dolomite, overlain by red sandstones, red and green shales, and some bedded gypsum, with signs of the former presence of bedded rock-salt. Flakes and crystals of haematite are common in many of the shales.

Upper Cambrian consists of greenish-brown shales and thin micaceous sandstones with dark limestones containing Lingula, Billingsella, Hyolites, and various trilobites. Locally, reefs of limestone contain abundant, large, Orthis-

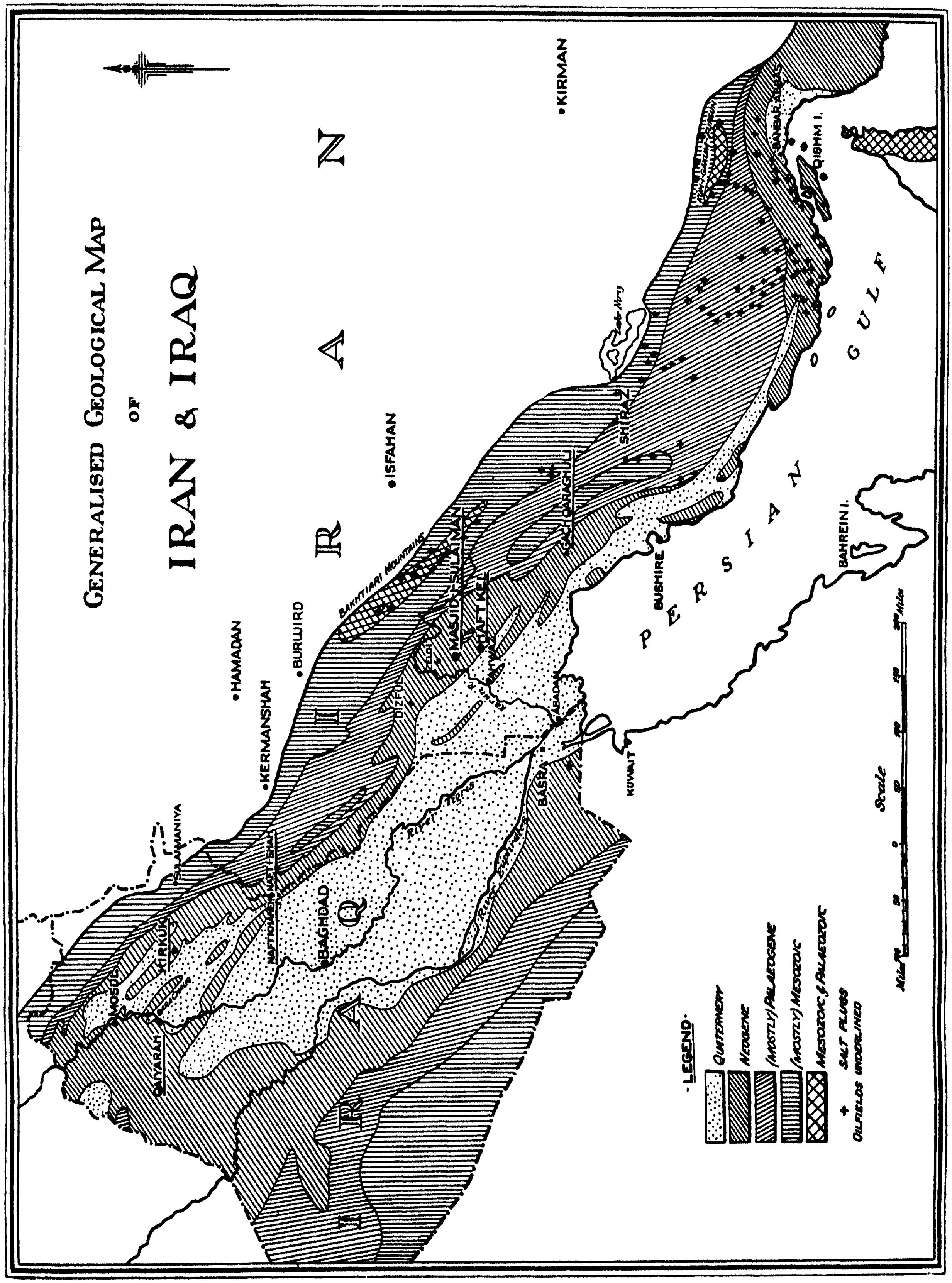

FIG. 1. Outline geological map of Iran and Iraq.

like brachiopods. The total thickness of Cambrian may be as much as 7,000 ft.

Salt-plugs. In addition to normal exposures, Cambrian rocks reach the surface through the mechanism of intrusive salt-bodies at numerous points in southern and south-western Iran and in the Persian Gulf. To date 130 of these salt-plugs have been discovered. The salt with its associated rocks was first named the Hormuz Series by G. E. Pilgrim [14, 1908], but no clue as to its age was forthcoming until 1924, when Middle Cambrian trilobites were discovered in shales and limestones associated with the salt-mass of Al Buza. The stratigraphy and structure of the salt-plugs were described by J. V. Harrison [4, 1930], to which work reference is made for further detail. These salt-masses are spectacular phenomena, but their effect on the concentration of oil is inconsiderable compared with that of the well developed normal anticlines among which they occur. It may even be negative in many instances.

The salt-plugs form intrusive stocks with an average diameter of about 4 miles and a subcircular cross-section; exceptionally they may emerge along fault-lines and have an elongate form. The salt-intrusions reach the surface through rocks of various ages from Cretaceous onwards. Some occupy the cores of anticlines, but most show no direct connexion with the normal folding, appearing on flanks or pitching ends of anticlines or even in synclines. Where the salt bursts through massive limestones there is little disturbance of the limestone around its periphery; but soft sediments, such as those of the Miocene and Pliocene, are steeply upturned around the edge of the salt-body. The salt carries up with it great detached masses of Cambrian rocks, purple-red and green shales and sandstones, buff and grey limestones and dolomites, black laminated foetid dolomites, and much anhydrite. The presence of the latter and of sandstones carrying salt-'pseudomorphs' point to an original association of these rocks with the salt, and the contained fossils give their age. (Many geologists hesitate to believe in a salt formation of such a great age and various attempts have been made to evade the issue. Krejci-Graf [9, 1928] suggested a Miocene age by assuming, with complete disregard for actual facts, great overthrusts; and more recently Kossmat [8, 1936] would prefer some such explanation. There is also a reluctance on the part of many geologists of the Indian Geological Survey to accept a Cambrian age for the salt of the Salt Range.) In many cases actual salt is not exposed, but its presence underground may safely be inferred from the abnormal appearance of this residual jumble of strange rocks occurring as a circular inlier surrounded by normal sediments; in other cases the plugs form mountains of bare glistening salt, reaching heights of as much as 5,000 ft. above the surrounding plains and forming the highest physical feature of the vicinity (Fig. 1). In these cases the salt is probably in a state of isostatic equilibrium and the yearly removal of material by rainfall is compensated by an equal rise of the salt-mass, thus maintaining its height above the surrounding limestones on its flanks. Harrison [5, 1931] and Lees [11, 1931] have shown that if the original position of the bedded salt is 20,000 to 30,000 ft. below the surface the greater specific gravity of the ordinary sediments can account for a column of salt rising to 4,000 ft. above surface-level.

The age of the salt movement ranges from Upper Cretaceous to Recent. Some of the plugs formed islands in the Upper Cretaceous sea, others in the Eocene and later seas, as is shown by the presence of conglomerates with 'Hormuz' detritus immediately surrounding the plug, whereas normally such conglomerates are absent. The salt-plugs which show evidence of early rise belong to a time before the present fold-system had developed, the later ones were in movement during the folding, while the intrusion of the youngest is subsequent to the folding and, in some cases, subsequent even to the development of the present topography.

(*b*) **Ordovician-Silurian.** The overthrust folds of Kuh-i-Furgun and Kuh-i-Gahkun, north of Bandar Abbas, expose some 200 ft. of dark, fissile shales with badly preserved graptolites (Monograptus, Diplograptus, and Climacograptus), provisionally assigned by G. L. Elles to Lower Valentian. The section is very imperfect; but the shales appear to be underlain by about 60 ft. of white quartzite, followed by 500 ft. + of sericitic shales, interbedded with thin quartzitic sandstone, full of fucoids and worm-tubes and frequently ripple-marked. The fucoid beds may be of Ordovician age.

Elsewhere in Iran where early Palaeozoic is exposed Ordovician and Silurian are absent.

(*c*) **Devonian.** The Silurian of the above localities is overlain by some 400 ft. of white, quartzitic sandstone with bands of green and dark shale, but fossil control of their age is lacking. They are followed by Upper Carboniferous limestones and so may represent the Devonian.

(*d*) **Carboniferous.** Marine Upper Carboniferous is probably represented in Kuh-i-Gahkun by limestones containing rugose corals, crinoids, and a productid fauna. In Bakhtiariland fossiliferous Permian overlies a group of brown-weathering sandstones and shales from which A. C. Seward [16, 1933] has identified *Sigillaria persica*, of age not greater than Westfalian and possibly Lower Permian. These beds lie without sign of angular unconformity on strata of Cambrian age.

(*e*) **Permian.** A thick series of dominantly calcareous strata extends from the Iranian-Iraq frontier near Halabja to Kuh-i-Furgun, north of Bandar Abbas. Locally, fossils (productids, fusulinids, corals) are fairly abundant in the lower half, but the upper limit of the strata assignable to the Permian cannot be determined.

3. Mesozoic.

(*a*) **Triassic.** Permian limestones pass upward without a break into the Triassic, which is represented by thick-bedded limestones and dolomites with, locally, subordinate hard calcareous or siliceous shales and some gypsum beds. Fossils are extremely scarce, but some species of *Myophoria* and *Pseudomonotis* (cf. Werfener Schiefer of the Alps) have been identified. In Kuh-i-Mungasht, east of Masjid-i-Sulaiman, a Middle Triassic (Carnic) fauna, containing *Gervillia socialis* and *Coenothyris vulgaris*, has been identified by J. A. Douglas, while south of Shiraz Upper Triassic is indicated by the occurrence of *Myophoria seranensis* and *Spiriferina altivaga*. For the most part the upper and lower limits of the Triassic are indeterminate, but the beds tentatively assigned to that age have a thickness of 2,000–3,000 ft.

In the zone of nappes the Triassic is present as a massive limestone formation carrying in its upper part abundant large megalodons reminiscent of the Dachsteinkalk of the Eastern Alps. These massive limestones are overlain, north-east of Kermanshah, by yellow and grey rubbly limestones and shales carrying an Upper Triassic Myophoria fauna and also the foraminifer *Orbitopsella*. This limestone-shale group passes upward into the thick series of red and green radiolarian cherts and shales which range

FIG. 2. Kuh-i-Namak Salt-plug. The salt extrudes through Cretaceous limestone, and the flow of salt downhill at either side of the plug can be seen

FIG. 6 View of the edge of the Turkidiz syncline at Masjid-i-Sulaiman showing the steep upturning of the Lower Fars. Tul-i-Bazun is on the right (see Section 1, Fig 4)

in age from, and perhaps include in part, the Upper Triassic through Jurassic into Lower Cretaceous.

(*b*) **Jurassic.** In the north-western half of the mountain-belt of Iran and Iraq the Jurassic is represented by a group of bituminous limy shales and thin limestones with chert bands, with a thickness varying between 250 and 1,000 ft. The limestones carry an abundant, though poorly preserved, fauna of small ammonites and are also rich in *Posidonomya*.

In Iraq, north-east of Zakho, Upper Jurassic has been recognized on the basis of the following determinations by Pringle and Chatwin:

Lithacoceras ardescicus
Virgatosphinctes vimineus
Ataxioceras?
Perisphinctes guentheri
Mytilus morrisi.

Farther to the south-east, Upper Jurassic appears to be absent but Middle and Lower Jurassic have been recognized throughout from Zakho to near Kermanshah. The thin-bedded limestones carry an Upper Bajocian fauna with *Stephenoceras* (of *coronatus* type), *Parkinsonia* sp., *Oppelia* sp., *Sonninia* sp., *Sphaeroceras* sp., *Morphoceras* sp. (determinations by Spath).

In the south-eastern half of the mountain zone the Jurassic is present as one component of a continuous thick-bedded limestone-formation which extends from Triassic into the Cretaceous, and in consequence of the scarcity of fossil-control the upper and lower limits of the Jurassic are indeterminable. A problematical shell at the base of the Jurassic is a thick shelled oyster-like organism which has been referred to *Lithiotis*, a form derived from the Lias of the Southern Alps and Croatia.

In the zone of nappes the Jurassic is represented by a thick series of red and green radiolarian cherts, red shales, and oolitic limestones; associated with them are great masses of green igneous rocks.

(*c*) **Cretaceous.** The Cretaceous may be divided lithologically into two groups, a lower with massive limestones predominating, and an upper with marlstones. The limestone division embraces the Lower and Middle Cretaceous up to the Cenomanian, and the marlstone division the Senonian and Maestrichtian, but for the most part it is uncertain to which group the Turonian should be assigned.

The Middle and Lower Cretaceous are represented as limestones throughout the entire length of the mountain-belt. In type, the limestones range from massive and thick-bedded neritic limestones or dolomites, carrying locally a rich fauna of oysters, large gasteropods, orbitolinas, and in its upper part rudists, to a thinner-bedded bathyal type, rich in microforaminifera and usually more or less bituminous. Subordinate developments of bituminous limy shales occur at different horizons, and, as a rule, yield abundant ammonites. In the north-west end of the mountain-belt, in Iraq, the Neocomian is composed of such limy shales and thin limestones, while the Aptian, Albian, and Cenomanian are continuous limestones. Farther south-east, in Iran, the more shaly zones are usually of Aptian or Albian age.

The Middle and Lower Cretaceous limestones are important feature-forming rocks, and they are responsible for most of the highest ranges. Where the limestones are hard and thick-bedded, strong features and heavy steep scarps result, while the thin-bedded bathyal facies tends to form smoother and more rounded hills. The thick-bedded limestones are folded into large simple units, whereas the thin-bedded type frequently crumples into a complex pattern of steep minor folds.

The upper lithological division of the Cretaceous is dominantly marly. Throughout the whole area the Senonian is almost uniformly represented by dark-coloured bituminous marlstones which on exposure weather light-blue, with some subordinate groups of thin-bedded limestones. The marlstones contain 60% or more of calcium carbonate and, although they crumble into small splinters on weathering and have the appearance of a soft formation, they are found to be hard and brittle and physically not unlike pure limestones when freshly exposed or where met in wells.

In Pusht-i-Kuh and at Imam Hassan, near Qasr-i-Shirin, the Senonian marlstones carry a rich fauna of oysters, echinoids, &c., the most prominent forms being *Gryphaea* (*Pycnodonta*) *vesicularis*, *Lopha dichotoma*, and various species of *Hemiaster*, *Iraniaster*, and *Epiaster*. The fauna indicates a Santonian or Campanian age. Elsewhere macrofossils are scarce but microfossils are very abundant, typical and diagnostic forms being *Globotruncana linnei*, *Globorotalia cf. globulosa*, *Globigerina* spp., *Anomalina* spp., &c.

The upper stages of the Upper Cretaceous, i.e. Maestrichtian and Danian, are, in the south-westerly zone, similarly represented by marlstones and thin marly limestones, but in the more north-easterly zone the effect of the Senonian movements still farther to the north-east is shown by the appearance of coarse detrital matter among the marls. (Danian is undoubtedly present, but fossil control of its limits is lacking.) The sands and conglomerates are formed almost exclusively of chert, felspar, and green minerals, which impart a dominantly green colour to the sediments. The Maestrichtian thickens up from about 1,500 ft. in the marly zone to about 5,000 ft. in this sandy zone. The sandy development carries a rich fauna including *Loftusia persica*, *Loftusia morgani*, *Omphalocyclus macropora*, *Cyclolites* spp. and numerous rudists. Locally reef-limestones composed of rudists are developed. Red shales and some gypsum beds are occasionally present.

4. Kainozoic.

(*a*) **Eocene.** The Upper Cretaceous deposition of marly sedimentation, alone or with sandy intercalations, continues into the Lower Eocene in much of the south-westerly zone. In a large area south-east of Shiraz the Lower Eocene is represented by a thick series of gypsum-beds and red marls (this may extend downward into the Upper Cretaceous).

Throughout much of the mountain-zone, particularly in the north-east, strong limestones, locally very rich in nummulites, commence with the Lutetian and continue through the Upper Eocene. Locally red marls are developed in the Middle and Upper Eocene.

In much of the south-westerly zone of Iran, as, for example, at Asmari Mountain and at Masjid-i-Sulaiman, the Middle and Upper Eocene are represented by thin-bedded marly limestones and marlstones with some bituminous beds, but in the equivalent zone in Iraq the Upper Eocene is present as nummulitic limestone and is important as forming part of the oil-reservoir rock of the Kirkuk oilfield.

(*b*) **Oligocene and Lower Miocene.** The uniform conditions of sedimentation which persisted in the Cretaceous and Lower Eocene throughout most of the Zagros belt were complicated in the Middle and Upper Eocene by the

local development of lagunar conditions and of limestone reefs. This process reached a maximum during the Oligocene and Lower Miocene, when areas of thick anhydrite deposition and areas of reef-limestone or of normal limestone form a complex pattern.

In the south, near Bandar Abbas, the Oligocene Khamir Limestone is a porous reef-development of nummulitic limestone and dolomite about 1,200 ft. in thickness, and the Lower Miocene is a gypsum-series. On Qishm Island, only 15 miles distant from Khamir, a well drilled through the Oligocene encountered a mixed shale- and anhydrite-series, but no limestone. In the country south-east of Bushire the Oligocene is represented by only about 50 feet of limestone with *Nummulites intermedius-fichteli*; the Lower Miocene is present as gypsum and shale.

From the Bushire–Shiraz road to Pusht-i-Kuh the Oligocene and Lower Miocene show a fairly uniform development as the Asmari Limestone—a limestone which has become famous as the reservoir-rock of the Iranian oilfields. It is described in detail in a later section.

In the frontal ranges of Pusht-i-Kuh, lagunar conditions prevailed, while in the more north-easterly ranges the Asmari Limestone facies continued. At Naft Khaneh the oil-reservoir rock consists of a limestone, locally known as the Kalhur Limestone, some 250 ft. in thickness, and this is underlain by about 400 ft. of anhydrite, salt, and thin limestones. The latter group is regarded as the time-equivalent of the anhydritic group of the middle section of the Asmari Limestone.

From the Iran-Iraq frontier near Chia Surkh to the Kirkuk oilfield the Lower Miocene has a conglomeratic development indicating pene-contemporaneous erosion. The components of the conglomerate are of local derivation and are cemented by limestone. The Oligocene is present as a porous dolomitic reef-limestone and in the case of Kirkuk, the Upper Eocene, also very porous, forms part of the so-called 'Main Limestone' reservoir rock of the Kirkuk oilfield.

(*c*) **Miocene and Pliocene.** Late in Burdigalian times the lagunar conditions, which had hitherto only had local development, became widespread, and the salt- and anhydrite-deposits of the Lower Fars were laid down in an immense gulf which stretched from the present Turkish frontier, north-west of Mosul to the Persian Gulf.

The Lower Fars is composed of anhydrite-beds associated with grey, greenish, or red marls, and a highly variable amount of bedded rock-salt. Further, the succession shows a number of thin limestones, some oolitic, some foraminiferal, and towards its basal part a few thin bands of bituminous shale. North-westwards, at Naft Khaneh and in Iraq, the limestone bands are much more numerous, and the lower part of the Lower Fars Group becomes a transition series to a dominantly anhydritic formation from a uniformly calcareous group beneath.

Economically, the Lower Fars is of great importance in forming the effective 'cap-rock' series to the reservoir limestone immediately beneath it, and for this reason it has been studied in a considerable amount of detail. In Iraq Lower Fars problems are comparatively simple. The salt-zone has allowed some independent movement of the upper strata over the lower in the axial regions of steep anticlines, such as Kirkuk, but the structural details can be controlled by good limestone-marker-beds at intervals throughout. Conditions in the main oilfield belt of Iran are rendered much more complex by much greater original thicknesses of Lower Fars and a greater development of salt, combined with more intense compression. The result is that there is in many places complete disharmony between the surface rocks and the more rigid Asmari Limestone beneath. A further difficulty in the past has been the absence or rarity of characteristic marker-beds throughout many thousands of feet of apparently uniform anhydrite, shale, and salt, but recently it has been found possible to use the microscopic texture of the anhydrites themselves for diagnostic purposes with notable success (Strong [17, 1937]). Certain minute mineral-inclusions are constant within individual anhydrites over long distances and different horizons in the Lower Fars are characterized by inclusions of various carbonate minerals, quartz or chalcedonic silica.

The Lower Fars has been subdivided in Iran into three stages. Stage I at the base consists of grey marls, anhydrites, and much salt, with some thin oil-shales and locally some limestones in the lower part. The cap-rock anhydrite at Masjid-i-Sulaiman and Haft Kel carries thin stringers of foraminiferal limestone, which facilitate its recognition and thus enable precautions to be taken before drilling into the reservoir limestone immediately below. The thickness of Stage I is exceedingly variable. Over part of the Masjid-i-Sulaiman field it is absent, presumably by non-deposition, while at Zeloi, 15 miles to the north-west, a well commenced in Stage I, reached its base at 10,680 ft., this amount being, of course, due to tectonic accumulation of an originally thick development.

Stage II is more regular in its thickness and behaviour. It consists of red and grey marls, anhydrite, and locally some salt, and has an average thickness of about 500 to 700 ft.

Stage III consists of anhydrite and grey marls with some shelly limestones. Structurally it conforms with the overlying Middle Fars rather than with the lower stages of the Lower Fars.

The Middle Fars is best developed in the area between Bushire and Ram Hormuz, where it includes up to 2,500 ft. of pale-greenish or grey marls and marly limestones containing an abundant molluscan fauna, conspicuous amongst which are large oysters of *Ostrea virleti* and *O. gingensis* types. It also includes huge masses of reef-limestones composed of calcareous algae and bryozoa with some foraminiferal and coralline layers. The group shows transitions to the chemical series below (interbedded gypsum, oolitic limestones) and the detrital series above (interbedded sandstones). In the neighbourhood of Masjid-i-Sulaiman the whole group is only about 600 ft. thick, and in Iraq a separate Middle Fars Group has not been distinguished.

The Upper Fars Group is composed of reddish, brownish, or greenish marls, separated at close intervals by 20–40-ft. bands of grey or brownish sandstone. Originally the name was confined to the lower 3,000 ft. of the detrital series, while the thousands of beds above, which are generally somewhat paler in colour, less coherent, and more or less pebbly, were called the Lower Bakhtiari Group. It now appears doubtful whether this distinction has anything more than conventional value. Deposition was continuous, and the transition from finer to coarser detritus was a gradual one, corresponding with a gradual uptilting of the north-eastern edge of the region, from which the materials came. The great break occurs at the end of the Lower Bakhtiari deposition, when the mountain-building revolution reached its culmination and the coarse Upper Bakhtiari conglomerates were deposited on the bevelled folds.

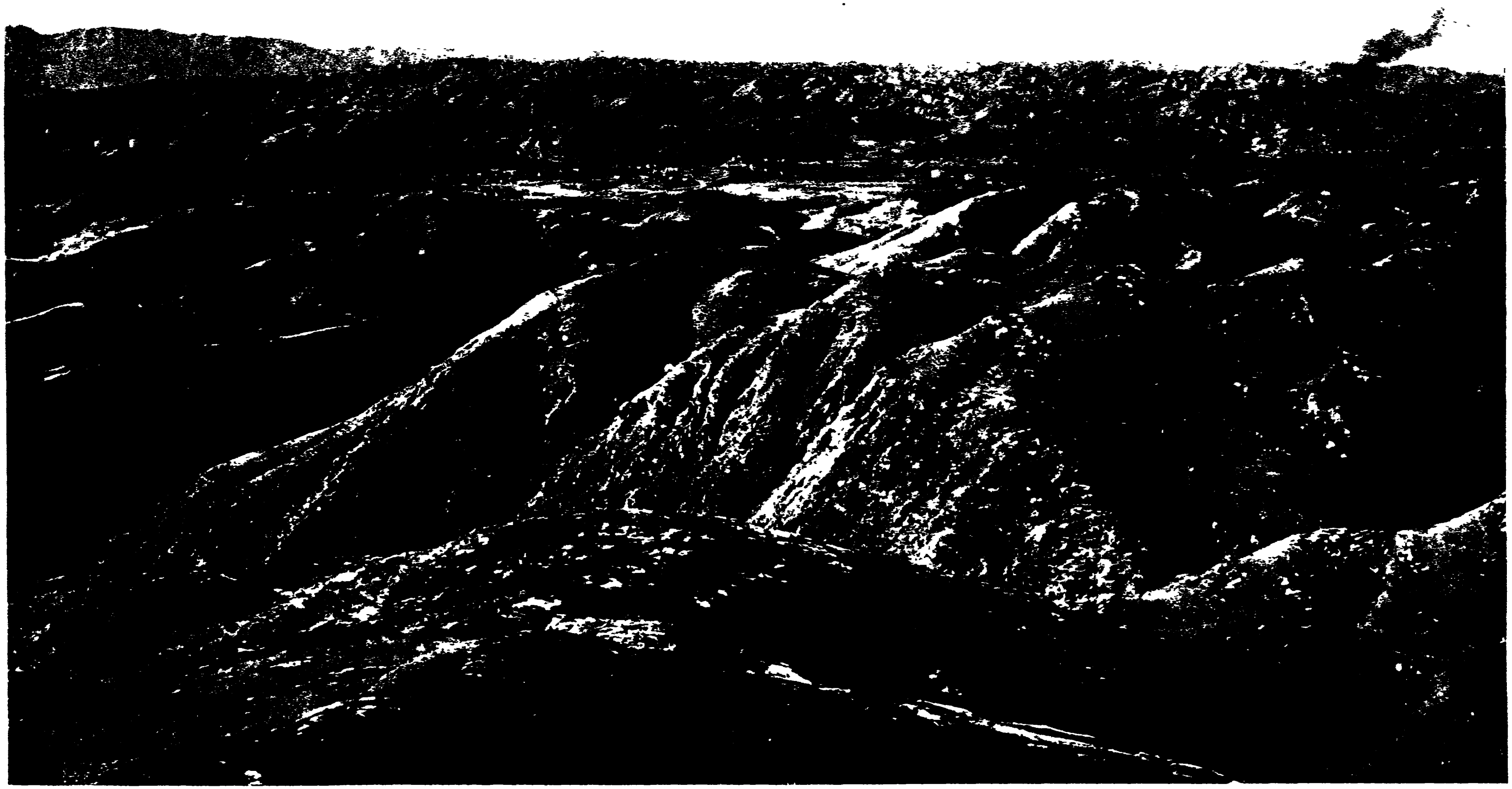

FIG. 5 View of the central part of Masjid-i-Sulaiman oilfield showing dissected Lower Fars landscape

Between Bushire and Agha Jari marine intercalations are present in the basal 2,000 ft. of the Upper Fars, and some horizons carry abundant large oysters (*Crassostrea gryphoides*) and, more rarely, a mixed fauna of echinoids and lamellibranchs. Farther north, however, the Upper Fars is completely unfossiliferous, and to place the boundary of the Miocene and Pliocene exactly is impossible.

Bakhtiari Conglomerates. As already stated, the cycle of deposition ends in most areas with coarse conglomerates, called the Bakhtiari Conglomerates, locally many thousands of feet thick, which, as they are usually lime-cemented, form prominent hill-features with steep scarp-faces. Lack of fossil-control prevents any exact time-correlation from area to area, and the age of the massive conglomerates is probably not constant throughout. In the mountain areas to the north-east folding-movements commenced earlier and the resultant conglomerates are probably older than is the case in the foot-hills.

The only palaeontological evidence of the age of the Bakhtiari series is from mammal bones and teeth. Pomeyrol collected at Qara Chauq Dagh various bones and teeth, among which Astre [1, 1936] identified a tooth of *Hipparion gracile*. G. M. Lees [10, 1927] discovered teeth and bones of *Hipparion gracile* cemented by asphalt in a conglomerate at Khadda Sur, north-east of Masjid-i-Sulaiman. Their age is approximately Pontian.

Mio-Pliocene of the Persian Gulf Littoral. The Mio-Pliocene beds of the Persian Gulf show a similar succession of lagunar, marine, and terrigenous deposits; but the most prominent development of gypsum-beds, which follows on the Khamir Limestone and was at first accepted as the equivalent of the Lower Fars Series of the oilfield area, has been found to be older and contemporaneous with the lower part of the Asmari Limestone. Later work has therefore discarded the Fars-Bakhtiari divisions used elsewhere in Iran and distinguished:

(*f*) Upper (Arenaceous) Group	Mio-Pliocene
(*e*) Lower (Argillaceous) Group	
(*d*) Upper or Operculina-Limestone	Miocene
(*c*) Red Beds	
(*b*) Lower or Gypsina-Limestone	
(*a*) Gypsum-series	

The Miocene reaches a thickness of some 4,000 ft. near Champeh, where the lower 2,500 ft. belong to the Gypsum Series (*a*). The Mio-Pliocene beds may be as much as 8,000 ft. thick, half of which thickness belongs to the arenaceous and half to the argillaceous division. The upper division locally includes some thick, massive, limestone-conglomerates similar to the Bakhtiari Conglomerates.

III. Oil Indications

Both the mountain belt and the foothill zone of Iraq and south-western Iran are rich in oil indications of various sorts. The Eocene, Cretaceous, and Jurassic marlstones and limestones carry numerous small veins and pockets of asphaltite ranging in type from semi-soft bitumens through hard brittle glossy 'manjak' to hard infusible and insoluble 'impsonite' with a carbon-hydrogen ratio of as much as 22 to 1. The field relationships of such occurrences, and the fact that such asphaltites can be met with in deep wells, show that they are not the products of inspissation of oil by exposure at the surface, but the detail of the process of their formation has yet to be satisfactorily explained (Lees [12, 1933, p. 4]).

Seepages within the mountain belt are much less frequent than the solid residues within the rocks, but they have an extensive distribution from Bandar Abbas to north of Mosul. For the most part they are small and unimportant, but in some isolated cases the yield amounts to several gallons a day and is sufficient, as in the case of Imam Hassan, to warrant its collection by the local inhabitants.

The most prolific oil- and gas-seepages are contained in the foot-hill zone. Many occur at or close to the outcrops of the Asmari Limestone and represent the last stages in the exhaustion of a one-time oil-accumulation resulting from exposure by erosion of the reservoir-rock, as at Dasht-i-Qil, 20 miles south-east of Gach-i-Qaraghuli; others occur in Lower Fars areas where erosion has weakened the cover-rocks of underground accumulations sufficiently to allow leakage to the surface. The oilfields of Qaiyarah, Kirkuk, Naft Khaneh and Naft-i-Shah, and Masjid-i-Sulaiman all show active escapes of oil and gas at the surface. At Haft Kel and Gach-i-Qaraghuli, where the thickness of cover is greater, only gas-escapes are present over the crestal areas of the underground reservoirs, and at White Oil Springs the light oil is regarded as a condensate from escaping gas. In many places solid or semi-solid bitumen deposits are evidence of an earlier escape of oil, in others, such as near Hit, extensive pitch lakes are formed.

Escaping gas in many places gives rise to a phenomenon named Gach-i-Turush (Iranian for sour gypsum). It is a deposit of soft powdery gypsum, white at the surface, but chocolate-brown beneath, containing many small or large sulphur crystals. Escaping gas may often be detected by an acrid pungent smell indicating an oxidation of sulphur gases. The gypseous earth is usually slightly damp, and tests have shown a free sulphuric acid content of up to 9%. In most areas of strong Gach-i-Turush there is a development of aragonitic limestones which seem to be the product of the action of hydrocarbon gas on original gypsum-beds, a reaction which would account for the richness in sulphur of the gas escaping at the surface.

In areas such as Masjid-i-Sulaiman, where a simple Asmari Limestone anticline is overlain by contorted Lower Fars beds, the escaping gas is concentrated into the crests of these minor folds and both the Gach-i-Turush and the development of aragonitic limestones are confined to these local areas. The Gach-i-Turush and secondary limestones are entirely superficial phenomena and are not encountered in any of the wells below a depth of about 200 ft.

IV. Structural Conditions in the Oilfields

1. Masjid-i-Sulaiman.

The Masjid-i-Sulaiman oilfield lies in a zone of extreme structural complication, as is shown by the accompanying section (Fig. 4, Section 1). The disharmony between the surface formations and the rigid limestone-mass, which includes the Asmari and the underlying limestones and marlstones, is the result of independent movement of great masses of salt within the Lower Fars and of the gliding of the upper groups on this mobile member. The conditions are further complicated by the fact that there were originally great differences in thickness, and particularly in the amount of salt deposited on anticlinal areas and in synclinal regions, the result of gentle warping during the early part of Lower Fars times. Thus, in the axial part of the north-western (or Asiab) half of Masjid-i-Sulaiman, Stages I and II of the Lower Fars are absent and Stage III rests directly on the cap-rock anhydrite immediately overlying

the Asmari Limestone, and detailed stratigraphical work on this problem has indicated that this condition is original and not due to tectonic attenuation. Farther south-east, on the present crest maximum, the Lower Fars is at the surface and seems to have had an originally greater thickness than on the line of section as shown, and structural complications are greater.

Experience with Lower Fars tectonics has shown that date it would be equally permissible, on surface evidence alone, to draw an Asmari syncline and thus to make the surface anticline the result of tectonic packing of the Lower Fars, and, in particular, of its salt members. A notable success in zoning the Lower Fars has been achieved in the Gach-i-Qaraghuli region, and by studying changes of original thickness it is sometimes possible to predict the position of Asmari highs in complicated Lower Fars areas, but in many cases imbrication of the Lower Fars at the surface, combined with confused exposures resulting from the solution of salt, makes this impossible. The value of geophysical assistance in such an area as Andakah does not require emphasis.

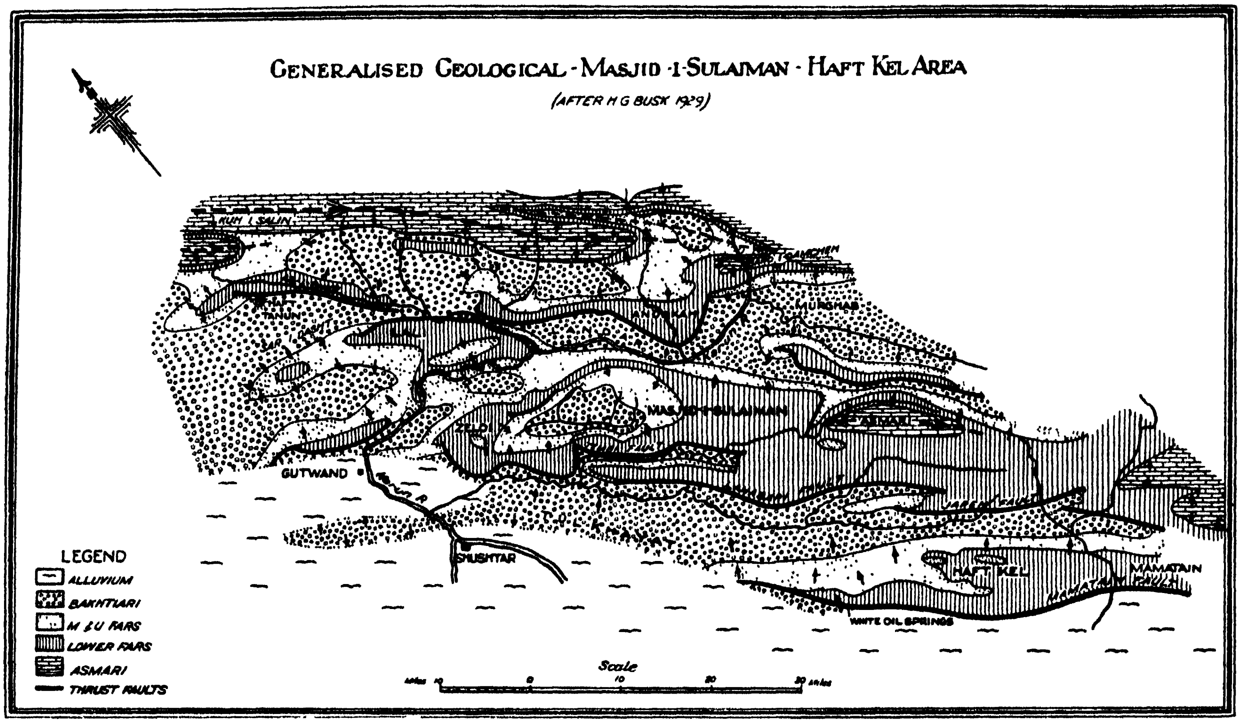

FIG. 3. Outline geological map of the Masjid-i-Sulaiman Haft Kel area.

in areas where the Lower Fars is thin there is an approximate structural concordance between it and the Asmari Limestone, but as the Lower Fars increases in thickness down-flank structural complications set in. The cross-section has been drawn to include three major anticlinal axes on which the thinness of the Lower Fars development has caused the upper structure to be more or less anchored to the Asmari beneath. These axes are the Haft Kel–Tulkhayat axis in the south-west, the Masjid-i-Sulaiman axis, and the Kuh-i-Kamerun axis (the line of section crosses the pitching end of a large anticline which farther south-east exposes Asmari Limestone and older rocks).

The subsequent compression of this zone formed a series of steep, overturned, and perhaps faulted anticlines in the Asmari Limestone, but the mobility of the great thickness of salt in the major synclines prevented the cover-rocks from conforming in detail. Masses of Lower Fars, impelled by the salt, were ejected and burst through at lines of weakness in the cover to form long diapir-like anticlines such as Imam Riza and Tul-i-Bazun. Some of these narrow diapir anticlines (the 'gamma' and 'omega' structures of Busk [3, 1929]) may be underlain by a flexure at depth, as is shown at Imam Riza, or they may be merely a blister which has grown on a monoclinal flank of the Asmari, as is shown in the case of Tul-i-Bazun.

The difficulty of diagnosing the underground conditions is illustrated on this section in the case of Andakah. The section shows a deep Asmari fold, but on experience to

The foregoing paragraphs describe the difficulties met with in attempting to locate anticlinal axes across the strike of the country. Along the strike the handicaps are equally formidable. Masjid-i-Sulaiman is in general terms a simple anticline in the Asmari Limestone separated from Asmari Mountain itself by a simple saddle. The north-western half of the Masjid-i-Sulaiman anticline pitches down under the surface Turkidiz syncline (Fig. 6). This surface syncline is flanked by the Lower Fars of Tul-i-Bazun on the north-east and by the Lower Fars of Sar-i-Naftak and Gach-i-Khalaj on the south-west. Farther to the north-west the Turkidiz syncline rises, and these two Lower Fars limbs coalesce in the Zeloi area in such a way that there seemed a high probability that the surface structure was the effect of an underground dome in the Asmari Limestone, separated by a saddle from the Masjid-i-Sulaiman unit. During the years up to 1930 a number of wells were drilled to explore this possibility, the deepest being Zeloi no. 2 which reached 5,655 ft.

Subsequently the problem was investigated afresh by both geological and geophysical means, and in 1935–6 a well, Pirgah no. 2, was drilled as a result. From a seismic reflection survey the depth of the limestone was assessed at

about 5,000 ft., but at 10,025 ft. the well was still in Lower Fars beds comparatively high stratigraphically, and as there seemed no prospect of reaching the limestone at a depth shallower than 15,000 ft. the well was abandoned. A fresh seismic survey suggested that the axis lies farther to the north-east, and a new well, Zeloi no. 4, has recently been drilled, which reached the Asmari at 10,680 ft. A production-test made after drilling into the limestone to 11,190 ft. yielded only water, but as a core taken indicated a dip of about 50° it is possible that even this well is not located in the best position. The core showed oil-saturation in the Asmari limestone.

2. Haft Kel.

The Haft Kel oilfield is situated on a crest maximum of a long anticlinal line which extends from south-east of Mamatain to Shushtar. Copious seepages at Mamatain drew attention in the early years of development to that area, but drilling results were then disappointing. Mamatain is separated by a saddle from the Haft Kel unit, and it is possible that the seepages at Mamatain may represent an escape of oil to the surface which had spilled across the saddle from Haft Kel. The crestal area of the Haft Kel field is marked by an active gas-escape, but the only oil seepage, a very small and sluggish spring of thick oil, is not situated on the structural crest.

In the central part of the Haft Kel field the Asmari Limestone is covered by a substantial thickness of Lower Fars which is strongly disturbed by numerous faults and steep minor folds, and the Lower Fars zone to the south-west of the Asmari axis is strongly overthrust. At the north-western end of the field the Lower Fars is much thinner and more regular in its behaviour, and the Upper Fars swings across the axis, marking a saddle between the Haft Kel unit and the next crest-maximum to the north-west at White Oil Springs. The White Oil Springs dome is interesting on account of the occurrence of strong gas-escapes and springs of a light straw-coloured oil of 0·779 specific gravity. For many years this oil was regarded as a product of filtration, but recent experience has indicated that it is in reality a condensate from escaping gas. The underground Asmari anticline has a gas-dome of substantial size, and a well in the Asmari Limestone in the crestal region struck a gas pressure of 2,600 lb. per sq. in. at 2,987 ft.

Section 2 illustrates the structural conditions on the Haft Kel axis itself and in the area between it and Asmari Mountain. Within this area the attitude of the Asmari Limestone cannot be determined by surface geology. It is not impossible that the packet of Lower Fars strata is much thicker than is shown, and that the surface structures are entirely the product of salt-movement. Certainly the only deep well drilled in this area, Yamaha no. 2, reached a depth of 8,960 ft., and of this thickness about 53% was rock-salt. Here again the scope for geophysical assistance is obvious.

3. Gach-i-Qaraghuli.

This oilfield, which at the time of writing is in an early stage of definition by exploratory drilling, lies 150 miles south-east of Masjid-i-Sulaiman and 50 miles inland from the Persian Gulf coast. In this case the attitude of the Asmari Limestone is rendered even more obscure than at Masjid-i-Sulaiman and Haft Kel by extreme disharmonic movements of the cover-rocks over the rigid Asmari block. There is, however, a certain similarity with Masjid-i-Sulaiman. The Seh Qalehtun Syncline is found superimposed on an underground arch of Asmari Limestone, in exactly the same way as the Turkidiz Syncline at Masjid-i-Sulaiman.

The structural picture, in so far as it is known at present, is shown on Section 3. To the north-east the Kuh-i-Khumi–Kuh-i-Dil mountain-group rises abruptly from an undulating plain of contorted Lower Fars. The mountain exposures show steep folding and compressed synclines, and it seems possible that much of the Lower Fars complication to the south-west is due to the expression of mobile material from compressed synclines of a type comparable with, but probably less intense than, the exposed examples.

It should be noted that the over-folding of the Asmari Limestone on the north-east flank of Kuh-i-Khumi is due to gravity-collapse and not to normal tectonics. This remarkable phenomena has been described by J. V. Harrison [6, 1934; 7, 1936].

4. Naft Khaneh and Naft-i-Shah.

These oilfields lie on the Iraq–Iranian frontier, 80 miles north-east of Baghdad. Compared with the oilfields in Southern Iran, the structural conditions are simple. Lower Fars rocks are just exposed in the core of a steep asymmetrical anticline, the south-western limb of which is steep and broken by a reversed fault, the effect being to displace the surface axis substantially to the south-west of that in the Lower Miocene limestone. The surface crest is marked by copious oil-seepages and strong gas-escapes.

V. Reservoir Rocks and Conditions

The reservoir-rock of the Iranian oilfields, Masjid-i-Sulaiman, Haft Kel, and Gach-i-Qaraghuli, is the Asmari Limestone of Lower Miocene and Upper Oligocene age. At Naft Khaneh and Naft-i-Shah the reservoir-limestone is approximately of the same age, but its development is different and it has been given the local name of Kalhur Limestone. At Kirkuk the reservoir-rock is of Oligocene and Upper Eocene age and the Lower Miocene has a lime-cemented conglomeratic development, which is of lesser value as an oil-reservoir.

The preponderant association of oil-seepages with the Lower Fars Series within the oilfield belt led at first to the conclusion that the oil was generated within that series. Later the hypothesis was formulated (Richardson [15, 1924]) that the oil was indigenous to the Asmari Limestone, or that it was associated particularly with a lagunar development of that limestone (de Böckh in Discussion to Richardson, 1924). Oil-indications were, of course, known from lower horizons, but such older oils were considered to have no connexion with the Asmari reservoir-system. Later experience, however, has shown that the excellence of the Asmari Limestone as a reservoir-rock is due largely to the efficiency of the overlying Lower Fars as a cover-series, and that the oil which lodges in this reservoir may have migrated upwards from the Eocene or from various horizons within the Mesozoic, and accumulated when trapped beneath the impervious salt-shale-anhydrite series of the Lower Fars. The exact age of the reservoir-rock is therefore not important, and the Oligocene-Upper Eocene limestone of Kirkuk has a function exactly similar to that of the Oligocene-Miocene Asmari Limestone despite its difference in age.

The Asmari Limestone at Asmari Mountain and at Masjid-i-Sulaiman has a thickness of approximately 1,000 ft. The upper half consists of thick-bedded greyish,

foraminiferal limestones; the lower half has many thin intercalations of marl and anhydrite, and at the base there is a strong 25-ft. bed of anhydrite. The limestone is mostly hard, dense, and of low porosity, but there are occasional beds of softer, brownish rock of porosity between 5 and 10%, exceptionally up to 15%, and the highest record is 22%. The rock under the conditions of strong compression and folding is freely fractured, and the high productivity of the Masjid-i-Sulaiman and Haft Kel wells is primarily due to the fissured condition of the limestone. Much of the total oil of the reservoir is, of course, held in the rock-pores, but the permeability of even the most porous bands is insufficient to allow the oil to flow into a well unless an open fissure is encountered, and there are isolated cases of wells which have penetrated the entire thickness of the limestone without obtaining any production. The fissure-system, on the other hand, is so strongly developed that there is free interconnexion between wells many miles distant from one another, a factor which permits of controlled production under ideal conditions.

The Asmari Limestone at Haft Kel and at Gach-i-Qaraghuli is similar in general terms to that at Masjid-i-Sulaiman, although there are some differences in detail. In both these places there are many lenticles of anhydrite in the upper part of the limestone.

The nature of the porosity of the Asmari Limestone has been the subject of much controversy in the past. At one time it was thought that there was a direct connexion between dolomitization and porosity (Richardson [15, 1924]), but subsequent more detailed work showed that this is not the case (Lees [13, 1933]). There is a certain admixture of magnesium carbonate in varying proportions throughout, but careful analyses have failed to show that the porosity is governed by this factor. The limestone as a whole has a ramifying system of mineralized cracks, some filled with calcite, others with anhydrite, more rarely with celestite. These veins are mostly tightly filled, but some have open vugs or enlarge into open cavities. The system of cracks which affords the present channels for fluid movement within the reservoir belong to a later phase, and many of the mineral-veins are traversed by such cracks. These cracks are mostly inclined at steep angles, and many show slickensided faces, although the amount of movement is usually small. Drilling results have proved some small faults, but they are relatively unimportant.

The Asmari Limestone outcropping on the pitching end of the mountain of that name is only 8 miles from the nearest producing wells of the Masjid-i-Sulaiman field, and although there is intimate fluid connexion throughout most of the oilfield, this condition cannot extend across the intervening saddle, since otherwise the withdrawal of oil would result in the free entry of new water from the water-table at Asmari Mountain. It is possible that the saddle area, having been less strongly compressed, is less fractured and, further, since the saddle is below oil-water level, such cracks as have formed may have been sealed to a large extent by mineralization caused by the surface carbonate- and sulphate-bearing waters meeting the brine of the edge-water system of the oilfield.

At Naft Khaneh and Naft-i-Shah the reservoir rock, the Kalhur Limestone, is about 250 ft. in thickness and is in part a foraminiferal limestone, in part somewhat dolomitic with only obscure traces of organic structure, and in part oolitic. It is underlain by about 400 ft. of anhydrite, salt, and thin limestone, below which lie marls and marly limestones similar to those underlying the Asmari Limestone at Masjid-i-Sulaiman. The anhydrite and salt indicate a locally intense lagunar phase, represented at Masjid-i-Sulaiman by the thin beds of anhydrite in the lower part of the Asmari Limestone. The basal part of the Lower Fars of this area carries a number of thin limestones or groups of thin limestones interbedded with anhydrite and shale, and these form part of the reservoir-system, being themselves interconnected and connected with the Kalhur limestones, probably by faults.

VI. Acknowledgements

This short summary of the geology of the oilfield belt is presented on behalf of the geological staff of the Anglo-Iranian Oil Company, Ltd. It represents the results of field work and observations made through many years by a large number of individuals, and it has not been possible to acknowledge separately the part played by each. The writer, however, is particularly indebted to Mr. B. K. N. Wyllie for assistance in the preparation of the manuscript.

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NOTE

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THE STRUCTURAL CONDITIONS OF THE KIRKUK OILFIELD, IRAQ

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In the article by G. M. Lees, the general stratigraphical and structural conditions of the Iranian-Iraq oilfield belt have been described. In the regional sense this belt forms one single unit, but when the detail of individual oilfields are studied there are, of course, many points of difference.

The following remarks and cross-section attempt to reveal some of the details of the Iraq type of folding. The interpretation here given represents the composite views and opinions held by the numerous geologists who have done a vast amount of geological work in Iraq.

The accompanying cross-section of the Kirkuk structure illustrates the difficulty of locating wells intended to encounter the subsurface crest of the anticlinal fold. Over a large part of the length of the structure only north-east dips are observed together with strike and transverse faults and minor wrinkling of beds on the north-east flank. The monoclinal dip offers very little direct evidence as to the subsurface position of the crest maximum. Likewise, in that portion of the structure where there is well-marked surface evidence of anticlinal reversal, the surface structure is scarcely an approximation of the subsurface crest in the productive horizon. This nonconformity of subsurface to surface folding is not due merely to asymmetry of the fold, but rather to the manner in which the various stratigraphic horizons have reacted to the folding.

The stratigraphy involved embraces at the top of the section a thick series of sands, gravels, and conglomerates (Bakhtiari). Below this is a sand, siltstone, and shale series (Upper Fars) followed by gypsum, anhydrite, siltstones, and limestones (Lower Fars). The basal part of the Lower Fars is a salt series separated from the Main Limestone (the productive horizon) by the Transition Zone limestone and anhydrite, the lowest member of the Lower Fars. The Transition Zone and Main Limestone members are rather massive, dense, resistant rock, while the overlying formations are comparatively soft and plastic and, in comparison with the limestones, are much more incompetent beds. This relative incompetence reveals itself in the manner in which the various horizons have reacted to the force of folding, as depicted in the diagram.

The Kirkuk fold parallels the north-west to south-east trend of the Iranian Mountain Range. Its somewhat sinuous shape indicates that the structure was formed in two stages, between which there was a strengthening and a change in direction of the fold-forming pressure. During the first stage the pressure came from a direction at right angles to the original shore and facies lines of deposition. Later, the pressure came from a more easterly direction. The effect of the first folding caused a thickening of the Salt Zone in front of the Main Limestone arch, making the south-west flank steeper in the Upper Fars and Bakhtiari than in the Main Limestone. This is evidenced in the south-west flank wells, where there is a tectonic thickening of the Salt Zone. Further pressure broke the steep south-west Fars/Bakhtiari flank and allowed the north-east flank to ride forward. The extent of this overriding cannot be determined, as immediately upon entering the Salt Zone the fault becomes a surface of slipping more or less parallel with the bedding. The result of the thrusting also was to pile up a thick mass of Fars and Bakhtiari in front of the Main Limestone crest.

At about this time, corresponding with the strengthening and change in direction of pressure, there began the deposition of the upper unconformable Bakhtiari gravels low on the north-east flank. The effect of this differential loading across the structure, accentuated by the change in the direction of the folding force, was that the Main Limestone was now most free to move upwards, high on the north-east flank. Subsequent pressure caused a further south-westward movement and flattening of the Main Limestone crestal area and a hollowing on the forefront of the limestone arch on the north-east flank.

In the Lower Fars the moving back of the Main Limestone crest caused the almost complete squeezing out of the Salt Zone high on the north-east flank, the materials moving over to the south-west of the crest and forming a crushed and mixed accumulation, such as encountered in the wells drilled and shown in the accompanying sketch.

The principal reason for this independence of movement of beds, and resultant nonconformity of structure in the surface and subsurface horizons, can be attributed to the mobility of the Salt Zone and relative immobility of the Transition Zone and Main Limestone. The salt has acted as a lubricant, facilitating the sliding and wadding of beds along the top of the more rigid limestone mass.

At some points along the structure it appears that the beds above the Main Limestone have merely glided over the stable subsurface arch. However, throughout most of the length of the structure the intensity of the folding has overthrusted and contorted the younger beds, as pictured. The limestone arch, as a whole, has remained stable, though it has suffered faulting locally.

In advance of drilling results, the head of the overthrust fault plane, the amount of thrust and the amount of wadding and compaction of beds are some of the problems open to conjecture. The attendant difficulty of forecasting the crest of the subsurface arch below such a confused mass of stratigraphy becomes apparent.

EGYPT

By Dr. P. VAN DER PLOEG

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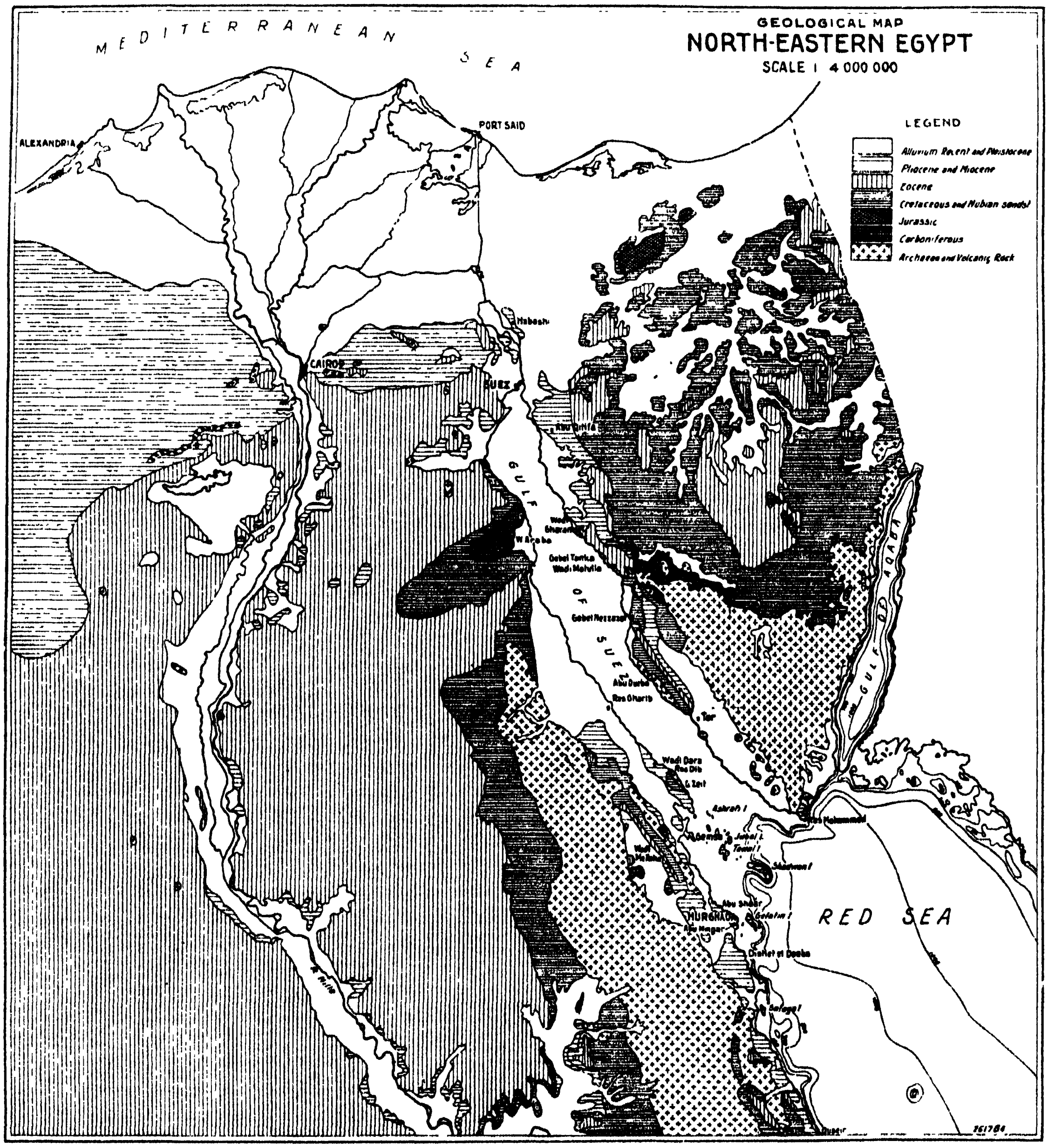
A GREAT part of Egypt is covered by sediments of Mesozoic and Tertiary age deposited by Mediterranean Seas over the slightly northward inclining African–Arabian crystalline shield. In Northern Egypt and Sinai these sediments have been folded in SW.–NE. striking ranges which, turning to the north, extend into Palestine and Syria. At right angles to the direction of these ranges rift valleys were formed—that of the Gulf of Suez and that of the Red Sea, with its eastern branch the Gulf of Aqaba. The development of these troughs is due to two main periods of faulting, one in the Upper Oligocene and the other in the Pliocene time. During the first period the relatively shallow Gulf of Suez trough and the border zones of the Red Sea were formed, whereas the much deeper subsidence of the central part of the Red Sea and of the Gulf of Aqaba took place in the second period. During this later time the movements also continued in the Gulf of Suez area, but were comparatively less violent there than farther south.



The Gulf of Suez area specially interests us for its oil occurrences. As may be seen from the igneous ranges of Esh-Mellaha, Zeit, and Abu Durba the subsidence of the crystalline rocks with their cover of Mesozoic and Eocene

strata occurred through step-faulting. The down-thrown blocks were tilted generally in such a way that an igneous front faces the sea and on the opposite side Mesozoic sediments are exposed, dipping away from the Gulf. Where such rigid blocks are covered by more plastic Miocene marl and marl-gypsum series subsequent vertical movements have caused, in addition to faulting, much dragging, squeezing, and superficial folding in these younger series. Such fold-like structures are, for instance, those of Abu-Mingar, Hurghada, and Eastern Gemsa, all three lying over igneous ridges, and Abu-Shaar, Ras el Bahar, and Wadi Dara situated between such ridges in depressions which, as a rule, contain thick masses of salt.

Hereunder the succession of the strata found in the Gulf area are given in brief:

Pleistocene:	Sandstones and oolites.
Unconformity.	
Pliocene:	Limestones, grits, and sandstones.
Unconformity.	
Miocene:	Limestone series.
	Lagoonal series: Marls, gypsum, salt, and limestone beds.
	Globigerina series: Green marls.
	Basal Beds: Reef-limestones, grits, and flint conglomerates.
Unconformity.	
Eocene:	Marl, gypsum and limestones with bands of flint.
Upper Cretaceous:	Limestones.
	Micaceous carbonaceous shales alternating with sand and sandstones.
Cretaceous and older:	'Nubian' sandstone.
Carboniferous: only at Wadi Araba, and central Western Sinai.	Limestones and sandstones with shale bands.
	Igneous.

The surface manifestations of oil are not too impressive in the Gulf area. There are five poor liquid oil seepages. The best one is on the shore near the south-eastern end of the Zeit range, another is in the old sulphur mines at Gemsa; the remaining three seepages rise from under water near the sea-shore, viz. at Gebel Tanka, Abu Durba, and east of the Jubal Islands. Outcropping impregnated sands of Cretaceous or Eocene age were found in the Wadis Gharandel and Matulla, near Gebel Nazazzat, and at Abu Durba.

In view of these indications much drilling has been done on both sides of the Gulf. On the Egyptian side 13 structures were tested and on the Sinai side eight. Most of the wells had gas- or oil-shows; production, however, has so far been obtained only from three fields, viz. Hurghada, Gemsa, and Abu Durba.

Hurghada is the most important of these fields, and the only one which is still producing. The field consists of two structures, both of which exploit or have exploited three oil horizons: Miocene Lagoonal Series, Miocene Basal Beds, and Cretaceous Sandstone Series. The oil from the Miocene is a lighter grade than that from the Cretaceous. Most oil has been obtained from the Cretaceous Series. The total production from both structures up to 31 December 1935 was about 4,000,000 tons.

The Gemsa field has yielded a total of only 180,000 tons of a light oil from a narrow belt on the crest of a steep structure. The oil was obtained from two Miocene dolomitic limestone horizons. Globigerina marls were not encountered in the wells, Lagoonal Series with Basal Beds lying directly on granite.

At Abu-Durba about 12 wells have been drilled, of which three gave production, yielding in all about 7,000 tons. The structure consists of two echeloned igneous fault-blocks, and the producing wells were drilled near the shore on the granite front of the structure into limestones, marls, and sandstones of dubious age.

There is still much difference of opinion regarding the origin of the oil in Egypt. The Cretaceous carbonaceous shales and the Miocene globigerina marls are each regarded as a possible mother formation. In view of the occurrence of the oil in Egypt apparently being confined to the Gulf of Suez area one feels inclined to associate the origin of the oil with a specific Gulf formation such as the Globigerina Marls. Whether outside the Gulf area oil is yet to be found, as, for instance, within the folded area of Northern Egypt and Sinai, future exploration will have to disclose.

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AFRICA AND MADAGASCAR

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THE continent of Africa has indications of oil in various parts, but if exception be made of Egypt, its oil production becomes almost negligible. During the past few years intensive research has been in progress in French Morocco. Wells have been sunk on various structures in this geologically complex region, and on the whole the results have been disappointing in that no important oil reserve has been discovered, yet the region is not considered to have been thoroughly tested [5, 1936]. Geophysical work has been carried out in Portuguese East Africa, and bores sunk in different parts of the continent have shown traces of oil, but many were drilled with little knowledge of the local geology and therefore were not adequate tests. Furthermore, some of the areas with oil indications are so difficultly placed geographically and topographically that only very large oil reserves can make their exploitation commercially possible.

North Africa. Seepages are known in the Larache district of Spanish Morocco, and are common in the triangular region, mainly in French Morocco, formed by Larache, Tizeroutine, and Meknes [1, 1932]. In the Rharb oil seeps are connected with Triassic diapirs and are near the Miocene-Flysch contact [2, 1932], and in the area as a whole seeps are reported from Triassic, Liassic, Cretaceous, Nummulitic, and Miocene deposits. Wells at various places, e.g. Bou Drâa (Jurassic), Ain Hamra (Miocene), have found traces of oil, and at times have given a small production. In 1934 a well on the broken, elevated Djebel Tselfat structure gave 250 tons of oil per day, but further work has shown the productive area to be limited to 120 acres, and to be partly water-flooded. The productive horizon is a Liassic limestone which appears to be or to have been oil-bearing over an area of at least 16 miles by 12 miles. Research has largely eliminated the possibilities of much oil in beds younger than the Jurassic, and efforts are being concentrated on finding Liassic limestones or older beds under suitably sealed conditions. The types of structure under investigation include folds with the Domerian crest near the surface; deeper crests beyond the frontal faults, and Liassic structures beneath discordant Cretaceous beds. The last group is of considerable importance, for this concealed condition obtains in about three-quarters of the suitable area in northern Morocco.

Most of the exploration in Algeria has been in the Oran region in the central part of the Tellian Atlas. There, seeps are either in Helvetian marls near dislocations with upthrust Triassic beds, as in the Tliouanet region, or in Sahelian deposits along lines of folding, as in the Chelif plain. A small oilfield has been developed at Tliouanet where 40 out of 100 wells drilled have produced from Helvetian sands. Wells in the Chelif plain have only penetrated the Sahelian and Pliocene, and have found strong water-flows and gas-blows in the upper Sahelian. Oil indications were found in the Sahelian at Ain Zeft, and an appreciable production was obtained, but no commercial field has been discovered in this region. Farther east bituminous Eocene limestones have been prospected by galleries at St. Arnaud, and bitumen occurs in Senonian (Fedj Mzala) and Triassic deposits (Ch. el Kraten). With the exception of the environs of Oran the evidences of oil in the Tellian Atlas are not considered important.

Oil indications are not common in Tunis [4, 1936]. The most pronounced indications are in the zone of isoclinal folding—at Ain Rhelal and Sloughia in Helvetian beds, and at Kef bou Debbous in the Cretaceous. A Triassic massif of gypsum and anhydrite forms the axis of Sloughia where wells drilled into the Miocene at seemingly favourable points found it to be mainly marly and to possess only traces of oil. Trias pierces the Miocene dome of Ain Rhelal on which a well encountered traces of oil in the Tortonian 260 ft. deep, and shows were also found by a well at Cap Bon which penetrated Lower Eocene limestones and Cretaceous marls.

West Coast. Evidences of oil have been found at various points on the west coast of Africa from the French Ivory Coast (Assinié) east to Duala in the Cameroons, and then south to Angola. A belt of sediments with a maximum width of 100 miles borders the coast in French Equatorial Africa [3, 1930]. These are of Cretaceous and Eocene age, with gentle undulations on the general westerly dip, and are covered unconformably by post-Eocene beds. The Lower Cretaceous 'sub-littoral sandstones' with shaly and dolomitic intercalations include beds which are richly impregnated with oil and which give seeps at Poumbou and in other localities. They are believed to be the source of impregnations in other beds, e.g. in the fissured, calcareous Middle and Upper Cretaceous sandstones at Pointe Noire. The Rembo N'Komi seeps are in Eocene (?) sandstones, and at N'Kogho, where an asphalt lake is reported, the inhabitants collect oil in pits. To the south in Angola oil seeps have long been known. Bitumen impregnated sands occur at Dande, and an exploratory well at Calumbo found several horizons with inspissated oil. To the north in the Cameroons oil and gas seeps are present round Duala, where a few wells have encountered traces of oil. Wells in the Gold Coast region have also revealed small amounts of oil and gas [10, 1929].

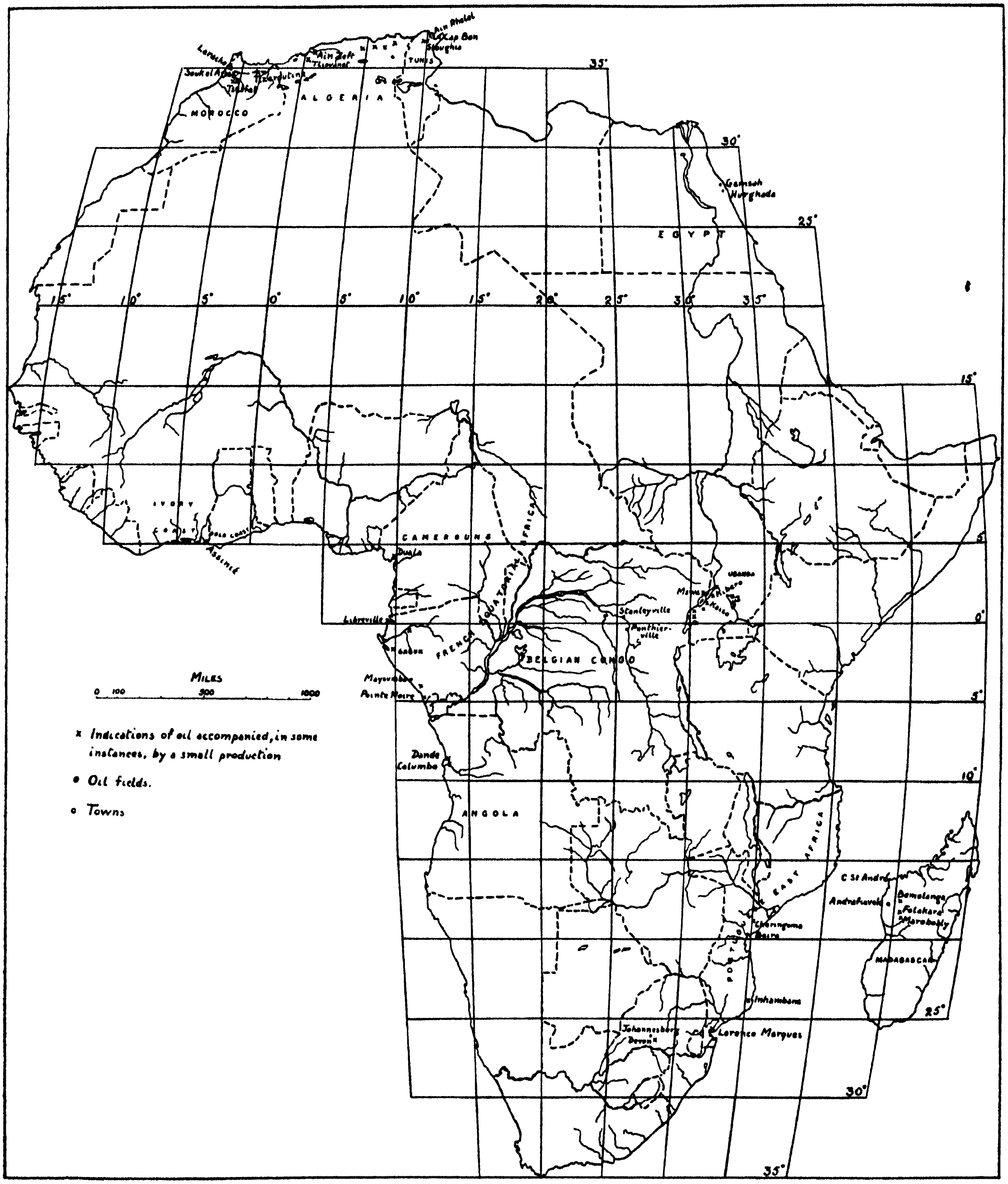
The Rift Valley Region of the Belgian Congo and Uganda. Oil seeps are known at Kibero and Kibiku on the Uganda side of Lake Albert, and at Mswa on the Congo side [9, 1926]; active and extinct mud volcanoes occur between Kisegi and Nybroge, whilst submarine gas eruptions have been reported in Lakes Albert and Kivu. The oil seeps in the Albert depression are not very conspicuous, for the unconsolidated and clayey nature of the Kaiso beds, and other factors, militate against this. Both the Kaiso and the underlying Kisegi beds contain sands, sandstones, and gravels capable of serving as oil reservoirs, but the latter series is considered to have the greatest chances of yielding important accumulations of oil. The gentle structures present are not unfavourable, and the indications are that the formation of oil is not a purely local phenomenon.

The Stanleyville-Ponthierville Basin of the Belgian Congo shows eleven bituminous shale beds in a brackish-water Juro-Triassic series. These beds have yielded 16–22 gal. of oil per ton, and Pirson [7, 1934] suggests that they may

have served as oil-source rocks in parts and fed structures towards the centre of the Congo Basin where they lie buried.

Portuguese East Africa. North-east of Lorenço Marques and in 1931 a well at Inyaminga encountered gas and several showings of oil.

Madagascar. The western side of the island of Madagascar is composed of Triassic to Quaternary beds with a



and in the Inhambane area oil seeps occur. During recent years interest has been shown in the Cheringoma plateau midway between Beira and the Zambesi and about 60 miles inland, where Upper Cretaceous and Eocene partly marine beds are exposed. Geophysical work has been carried out, general westerly dip. For 200 miles from the river Manambolo northwards to Cape St. André oil seeps are known, the most important of which are centred on Bemolanga and Morafenobe, and whilst some occur in Jurassic and Cretaceous beds, the bulk are in Triassic or Permo-Triassic

sands and sandstones [6, 1930]. Many igneous dykes penetrate the sediments, and the degree of oil impregnation appears to be proportional to the size and number of the dykes. Wade [8, 1929] was of the opinion that the oil had been produced in abnormal amounts by igneous distillation of carbonaceous horizons in the Permian (there are high volatile Permian coals at Benitra) and to a less extent in the Trias, though Nicolesco observes that bituminization in some areas has been recognized as pre-igneous injection. The discontinuous nature of the clays in the Trias has not favoured the preservation of oil. Development of the oil-impregnated surface sands by mining has been considered, and numerous wells have been drilled in the Folakara and Maroboaly areas near seeps, but they found only insignificant shows of oil. Better results are expected farther west where the Trias is covered by Jurassic and Cretaceous, and the Triassic clays are probably better developed.

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U.S.S.R.

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THE U.S.S.R. is second to the United States of America as an oil-producing country, having given 12·37% of the world's total production up to the end of 1935, and having occupied second place on the world list for annual production since 1873, with the exception of the period 1918–26 inclusive, although in recent years Venezuela has become a serious challenger. Various manifestations of the presence of oil and gas have long been known. Natural gas issues on the Apsheron Peninsula were used in the temples of certain sects, and thither fire-worshippers and Hindus of Burma and India made pilgrimages for over 2,500 years. As recently as 1880 priests are said to have conducted ceremonies in a temple at Surakhany. At times there have been fierce outbursts of oil and gas, startling the people and causing damage to property and even loss of life. Mud volcanoes are common, some erupting at intervals of a few years, and during earthquakes gas has escaped from cracks in the earth and become ignited.

The production of oil from hand-dug pits on the peninsulas of Kertch and Taman was described by the Greeks in ancient history. The first well in Russia was drilled at Balakhany in 1871. Previous to that a considerable output had been obtained from hand-dug pits, and as late as 1923 the bulk of the oil at Binagady was derived from 3,000 pits [6, 1923]. Oil seeps and 'kir' (asphalt) deposits in the Ferghana Basin were used in early times by the Chinese and Turkomans, and there shafts were sunk early in the 19th century. Drilling began in the Ferghana Basin in 1898.

The oil fields of the U.S.S.R. are widely spread and are found in the Caucasian region, the trans-Caspian area, the Ferghana Basin, the Ural-Emba region, at several points west of the Urals, and in northern Sakhalin Island. In 1935 the oil production was distributed as follows [19, 1936]:

	Azerbaijan	*NE. Caucasus (Grozny area)*	*NW. Caucasus (Maikop area)*	*Ural Permian*	*Emba*	*Sakhalin*
Millions of barrels .	136·43	23·3	8·34	2·84	1·7	1·65
Percentage of total	77·2	13·2	4·72	1·61	0·97	0·93

The Caucasian Region

The U.S.S.R.'s main oil production has been, and still is, associated with the Caucasian belt. The Caucasus range runs approximately WNW.–ESE. for about 1,100 km., and is formed of folded Palaeozoic and younger rocks. At its west-north-west end is the Taman Peninsula, and at the east-south-east end is the Apsheron Peninsula. The structures are simpler on the northern margin, and it is there and on the Apsheron Peninsula that the principal oilfield areas lie. Traces of oil and bitumen are found in Mesozoic and Tertiary beds on the southern flank, an almost continuous belt of oil indications runs along the northern slope from the Taman Peninsula to Maikop, oil seeps occur in the Grozny area and southern Daghestan, and mud volcanoes and gas and oil seeps are numerous on the Apsheron Peninsula.

The Apsheron Peninsula.

The following stratigraphical column for the south-eastern Caucasus (Table I) is essentially that of Golubiatnikov and Goubkin [7, 1934].

TABLE I

Quaternary	Recent mud volcano material and alluvium. Recent Caspian deposits; sand, clay, shells. 10 m.	
Upper Pliocene	Ancient Caspian	Upper and middle stages; conglomerates, sands, sandy clays, limestones. 66 m.
		Baku stage; conglomerates, sands, sandstone, sandy clay, limestone. 60 m.
	Unconformity	
	Apsheron stage (marine)	Upper; limestone, sands, clay. 180 m.
		Middle; sands, sandy limestones, calcareous sandstones, marls, clays. 170 m.
		Lower, sands, clays, dark clays with volcanic ash. Gas sands at Bibi-Eibat and Surakhany. 240 m.
	Clay with Limnaea (marine). Clay with marl. 138 m.	
Upper and Middle Pliocene	Akchagyl stage (marine)	Black clays, calcareous clays, sands, volcanic ash, marls, limestone. Petroliferous at Surakhany. 38–60 m.
	Productive series (fresh-water) (terrestrial)	Upper division; clays, sandy clays, sands, lenticular sandstones. 644–826 m.
		Middle division; coarse sands with rock fragments and lumps of clay; sandstone lenses. 154–243 m.
		Lower division; sands, sandy clays, sandstones. 219–394 m.
	Unconformity	
	Pontian stage (brackish and marine)	Upper (Babajan) horizons; dark grey clays, siliceous marls, lenses of detrital limestone. 50 m.
Lower Pliocene		Middle horizon; dark grey clays, siliceous marls. 33 m.
		Lower horizon, dark grey shaly clays. 216 m.
	Sharp break and unconformity in Kabristan.	
Upper and Middle Miocene	Diatom beds (marine)	(Analogous to Meotian and Upper Sarmatian.) Clays with siliceous concretions, white and light grey diatomaceous clays. Oil at Binagady. 136 m.
		(Analogous to Middle (Cryptomactra) and Lower Sarmatian.) Clays with interbedded siliceous marls. 270 m.
		Spaniodontella beds; dark grey, shaly clays with siliceous marls.
	II Mediterranean (marine)	Spirialis beds, 65 m ; Chokrak-Spirialis beds of Kabristan, 500 m. Dark grey, shaly clays; siliceous, dolomitic limestones. Petroliferous sands at Cheil Dag.
Lower Miocene	Maikop beds (marine)	Upper (Cedroxylon) horizon; laminated chocolate-brown clays with yellow ochreous formations. 200 m.
Oligocene		Lower (Amphisyle) horizon; thin alternating layers of chocolate-brown and greenish-grey clays; yellow-brown marl; bituminous in places. 130 m.
	Kown series (marine)	Green clays and sandstone, brownish-black clays, bituminous shales; white and greenish marls, and marly clays with green friable sandstones; local indications of oil throughout series. 200–600 m.
Eocene (marine)	Sumgait series	Clays and sandstones. 100 m.
	Ilkhidag series	Dark clays, coarse sandstones. 300 m.
	Yunus-Dag series	Reddish-brown and grey clays and marls; glauconitic sandstone and breccia limestones. 200 m.
Cretaceous (marine)	Orbitoidal series	White marls, hieroglyphic sandstones, breccia limestones. 550–600 m.

The upper division of the Productive series has three parts which are, in descending order, the Surakhanian

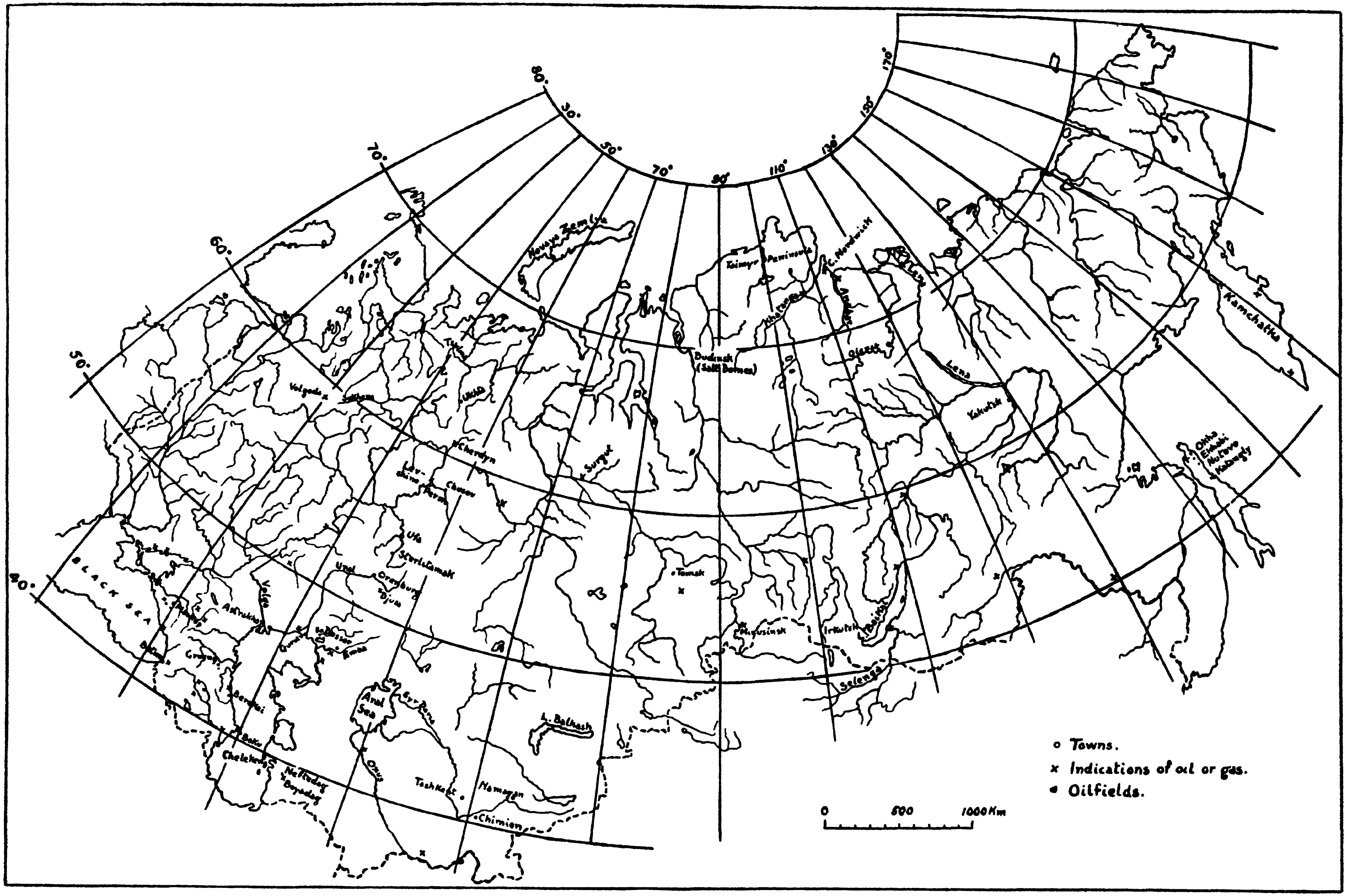

FIG. 1. Distribution of oilfields and indications of oil and gas in the U.S.S.R.

Sabunchian, and Balakhanian. The middle division or 'Break' contains water-bearing horizons, and the lower division is subdivided into super-Kirmaku clays, super-Kirmaku sands, Kirmaku proper, and sub-Kirmaku. The upper division is petroliferous at Bibi-Eibat, Surakhany, Kara-Chukhur, Balakhany-Sabunchy-Romany, Kala, and Lok-Batan; the middle division gives oil at Binagady, Balakhany, Mount Atashka, and Lok-Batan; and the lower division is oil-bearing at Puta, Mount Atashka, Sulu-Tepe, Khurdalany, Baladjary, Binagady, Holy Island, and Bibi-Eibat, but principally at Balakhany-Sabunchy-Romany.

The Productive series increases in thickness from west to east.

TABLE II

(*After Stutzer*)

WEST EAST

Sumgait and Kura valleys, Sallani steppe	*Northern part of Kabristan. Agsi-Kir Tatar*	*Binagady*	*Kirmaku Balakhany*	*Holy Island*
0 m.	360 m.	1,009–40 m.	1,240–70 m.	1,900–2,000 m.

Goubkin suggests that several oil-bearing series were deposited in this area: (1) the bituminous shales and oil shales of the Sumgait series; (2) the Brown Kown which is a typical sapropelic rock; (3) the Maikop series; (4) the Spirialis beds; and (5) all the Diatom series with fish remains as well as diatoms.

West of the base of the peninsula, the axes of the branching, irregular structures tend to run mainly WNW.–ESE., whilst in the east those of Kala and Holy Island (Fig. 3) trend more in a NNW.–SSE. direction, but in the principal productive area Baku is almost encircled, and immediately to the west is another almost complete ring, on the undulations of which lie the fields of Shubany, Lok-Batan, Puta, and Ker-Gez. Many of the structures are characterized by an increase in the dip of the strata on approaching the axes of the uplifts, and evidence, in the form of a more complete succession in the depressions than on the uplifts, shows that they have been rising through long geological periods. These features are regarded by some as an indication of the diapiric nature of the structures and, indeed, in some the discovery of a piercing core of Lower Tertiary clays is reported. Goubkin believes that the conditions favouring the formation of diapirs would also favour the accumulation of organic matter and its transformation into oil and gas, and, at a later stage, their movement towards the elevated core. Water would move with them softening the clay core, and subsequently mud volcanoes and gas

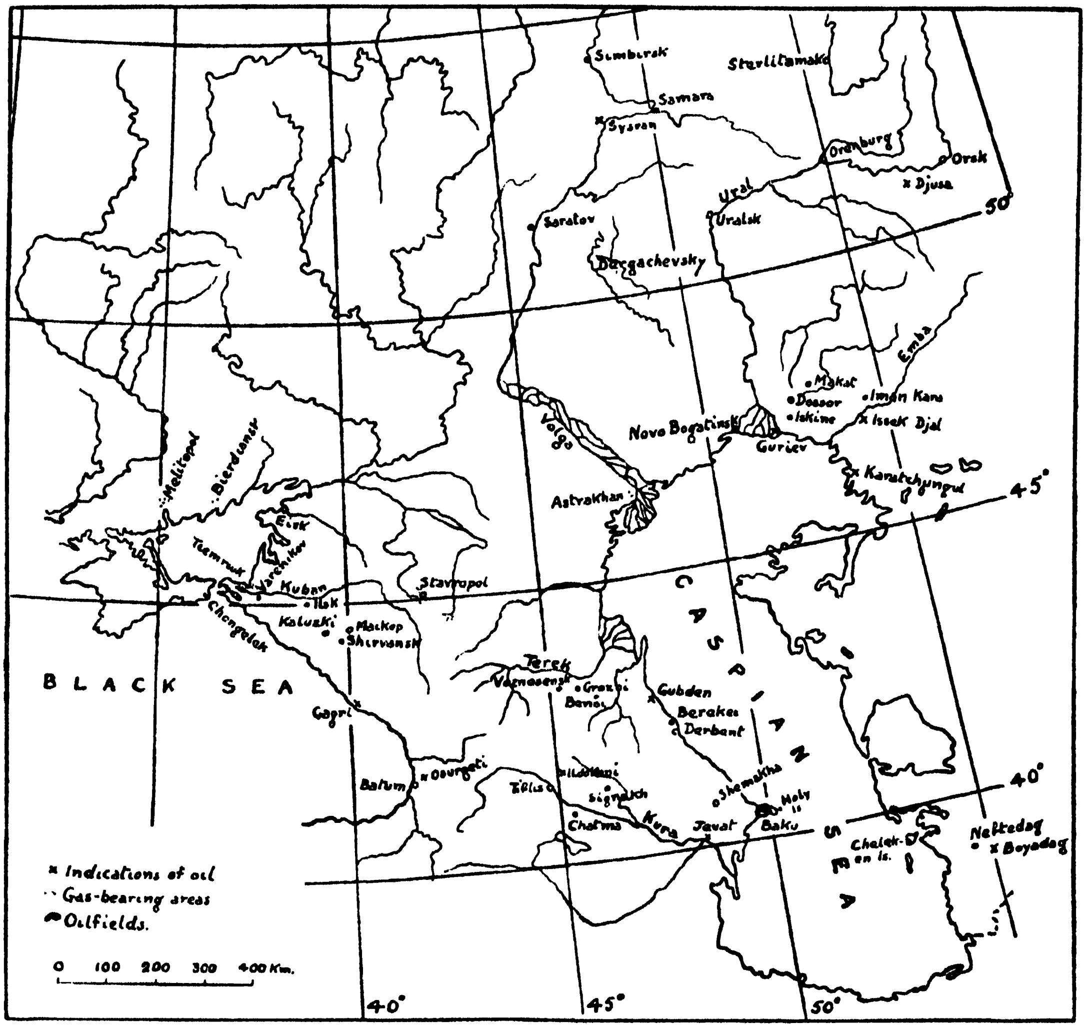

FIG. 2. Map showing the positions of some of the oil and gasfields and indications of petroleum in the Caucasian, Trans-Caspian, and Ural-Emba regions.

seeps would appear. The intrusive core would make fissures in the surrounding strata, thus aiding movement of fluids. The retention of oil and gas in any porous beds they may enter depends on the presence of an impervious cover, e.g. Akchagylian and Lower Apsheronian, and the sealing effect of the piercing core. There is evidence of the rise of some of the cores within recent years, but since it appears that mud volcanoes can eject blocks weighing as much as 100 tons, caution must be exercised in examining these structures for intrusive cores.

Fatmai, Kirmaku, Bog-Boga or Balakhany-Sabunchy-Romany, Binagady, Atashka, Lok-Batan, Puta, and some Kabristan structures are classed as diapirs by Goubkin. Other structures are more normal anticlines or domes, although some may have a rising core which has not reached the surface. To this group belong Surakhany, Bibi-Eibat, Kara-Chukhur, and Kala.

Each field on the Apsheron Peninsula has its own special characteristics as to number of oil horizons, their degree of saturation, and the nature of the crude. Correlation of parts of the Productive series is therefore difficult. Saturation of the oil sands varies in both dip and strike directions, and is most uniform in the lowest division. Even if the Productive series outcrops and is barren at the surface, it is commonly well saturated with oil at depth. The faults on the Apsheron Peninsula structures are generally small, but they affect the distribution of oil and water.

The Balakhany-Sabunchy-Romany uplift, which is broad and faulted, runs mainly west–east for a considerable distance. A part of an intrusive core of Kown is said to be visible in the Bog-Boga mud volcano at its western end. The structure plunges eastwards and the productivity increases in that direction. The upper division of the Productive series has 34 oil sands but is approaching exhaustion, and exploitation of the lower division has begun. Correlation is difficult and wells are often independent, pointing to lenticularity of the sands. The oilfield waters are at temperatures of 19·8–43·4° C., and water shut-off difficulties increase with depth.

Surakhany is a broad, flat arch running north–south, with dips of 10–20° to the east and 4–10° to the west. The crest is much faulted, especially at the southern end. The lowest Middle Apsheron beds outcrop in the centre. There are many gas seepages, and gas is first struck in drilling at depths of about 10 m. All the porous beds in the upper strata have gas, and 23 gas sands are encountered from depths of 36 m. to 480 m. The shallow gas area is about 5 km. by 1·5 km. A white (filtered) oil is found at depths of 200 m. in the top of the Akchagylian, and down to 335 m. five white oil sands occur. Black oil is found at 480 m. and deeper in the Productive series. Emmons [3, 1931] observes that Surakhany is probably the richest field in the world for its size.

South of Surakhany lies the Kara-Chukhur field on a north–south anticline with two branching longitudinal faults. The first well was drilled in 1929, but the principal development dates from 1933. Yet farther south is the flat dome of Zykh, the major axis of which trends NNE.–SSW. and plunges south-south-west. The dips of the flanks are 6–12°. Lower Apsheron beds are exposed on its crest and a mud volcano flow shows fragments of Amphisyle beds. In 1935 the discovery well was brought in at a depth of about 1,750 m. with a production of 7,000 bbl. per day.

The northern branch of the line of uplift, which appears to fork west of Bog-Boga, passes through Kirmaku and Fatmai. Both are considered diapiric, the former showing

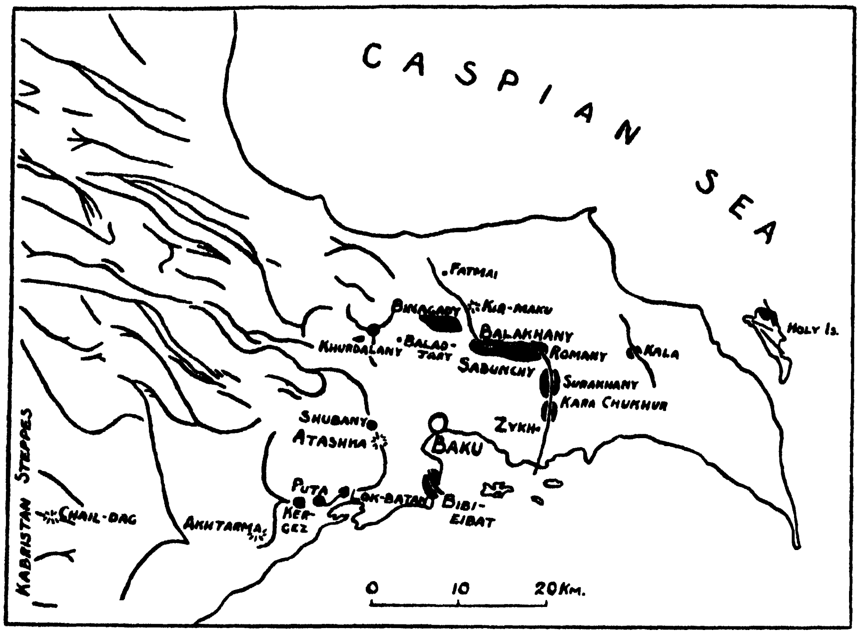

FIG. 3. Map of Apsheron Peninsula, showing the structural trends and the locations of the oilfields. (*After Goubkin.*)

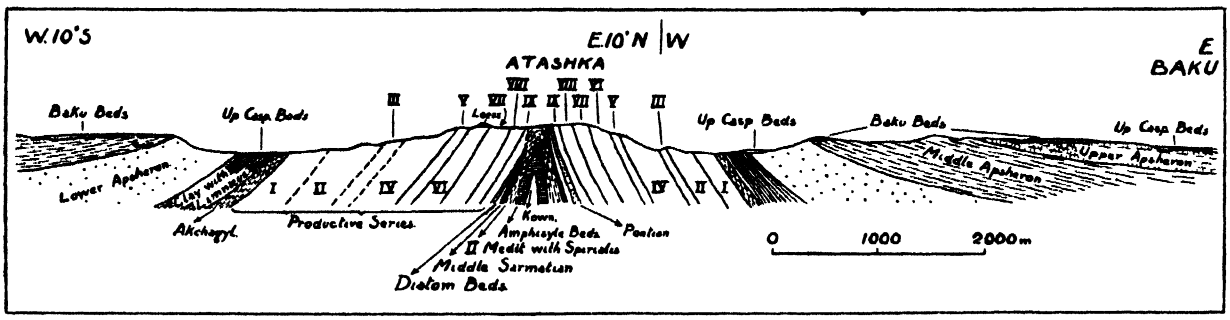

FIG. 4. Cross-section of Atashka. (*After Golubiatnikov.*)

a small core of Kown and the latter green Kown clays and Maikop beds enclosed by the Spirialis series. In the south-east of Fatmai small amounts of oil have been found in the lower parts of the Productive series. The southern branch runs through the broad, faulted Binagady arch in an east–west direction. The piercing core is of white Kown, flanked by Diatom beds on the north and south. There is a good development of Pontian on the southern side, but it is uncertain on the north, where the lower division of the Productive series approaches the core and is cut off by a fault. On the south the lower division is almost fully developed. Production began in 1901. The richest oil sands are mainly in the lower division of the Productive series and on the southern flank, but recently oil has been found on the eastern plunge and on the northern flank.

In the north-eastern part of Baladjary are hand-dug pits and a large asphalt sheet. The beds dip at about 45° to the south-east. Oil production is from the lower division of the Productive series. Khurdalany is a faulted anticline on which a heavy oil has been obtained from four horizons in the Productive series. Hand-dug pits had a considerable output in 1914. At Shubany-Atashka is a sharp north–south fold with the eastern flank dipping at 70–80° and frequently overturned, whilst the faulted western flank dips at an average of 65°. The structure plunges southwards at 15–25°, and there appears to be a core of Maikop beds. Strong gas vents and asphalt deposits are present, and the 30 oil sands in the Productive series are exploited by hand-dug pits and wells.

Lok-Batan is believed to have a core of Maikop clays which pierces the lower horizons of the Productive series. On this structure is a large mud volcano that erupts at intervals of 3 to 5 years. Here and elsewhere it has been found that the mud volcanoes affect only small areas, and the normal stratigraphical sequence is met after passing through 30–50 m. of mud volcano deposits. The discovery well was drilled in 1932 and gave 7,000 bbl. of oil per day. Nine producing horizons lie between depths of 900 m. and 950 m., and it is stated that the sand saturation is the highest ever known in the world. On the faulted Puta anticline early production was from hand-dug pits, the first commercial production from wells being in 1926. Only the upper and middle parts of the oil measures of the Ker-Gez structure had been tested in 1933, when 10 wells were giving a good output.

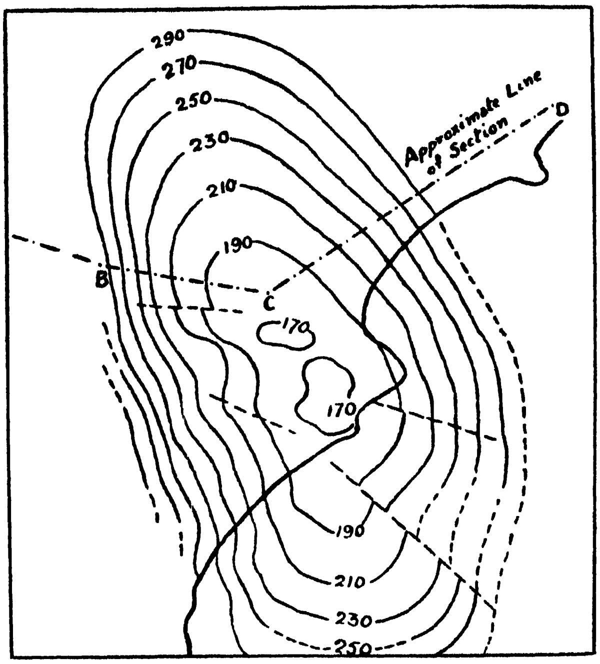

FIG. 5*a*. Stratum contour diagram of the Bibi-Eibat field. (*After Stutzer.*)

Bibi-Eibat is a broad, faulted dome with its major axis running NNW.–SSE. On the crest are two subsidiary elevations. The top of the dome is formed of Akchagyl beds and the upper parts of the Productive series. On the limbs are the Apsheron beds dipping at 7–22°. Ignoring beds of inspissated oil and gas shows in the upper beds, the first important pay is 90 m. deep. From there down to 640 m. are 20 workable sands totalling 120 m. The Productive series is believed to be 800 m. thick, and the lower divisions were untested up to 1935, but were expected to be prolific. Much of the field is on land reclaimed from the Caspian Sea.

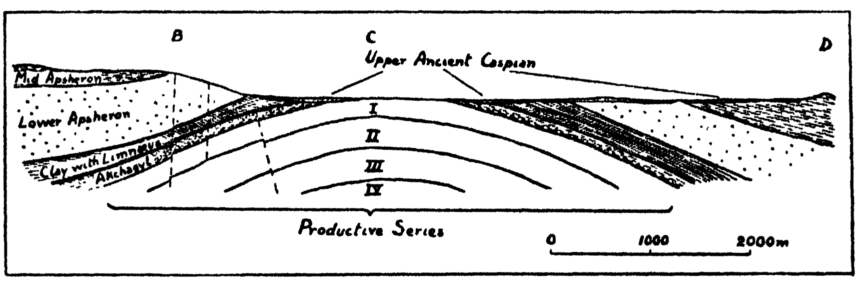

FIG. 5*b*. Cross-section of the Bibi-Eibat field along the line marked on Fig. 5*a*. (*After Golubiatnikov*).

The elliptical dome of Sulu-Tepe has its major axis north–south, with the eastern flank dipping at 80° and the western flank at 50°. Oil is found in the lower division of the Productive series. The Kala structure trends NNW.–SSE. and is similar to Surakhany, though deeper. There are many faults, and a transverse fault divides it into two parts, of which the northern is rich in oil and gas, whilst the southern part is barren in the upper Productive series. Some white oil has been produced. The apex of the Apsheron beds lies over one flank of the oil-bearing horizons, thus accounting for the many failures to locate oil.

The productive anticline on Holy Island strikes NNW.–SSE. Its west-south-west flank is gentle, whilst the east-north-east flank is steep, overturned, or even overthrust with a reversed fault. There are two secondary folds with the same strike and faults. Ancient Caspian deposits rest unconformably on the Pliocene, and the Apsheronian, Akchagylian, and upper part of the Productive series are missing. Oil has filtered into the post-Pliocene sediments, giving deposits of kir in the north-east, and outcropping oil sands are commonly sealed with asphalt. Nineteen oil sands are known. The southern anticline is little prospected.

The Region West of the Apsheron Peninsula.

In Kabristan west and south-west of the Apsheron Peninsula, on the east–west anticlines of Cheil Dag and Akhtarma oil indications are connected with the upper part of the Diatom series, the Spirialis beds, and the upper part of the Maikop formation. Pakhomov [11, 1932] reports that the last is most important because of the presence

of an arenaceous facies. Some wells have given oil on Cheil Dag. The value of the diapiric structures of Kabristan is undetermined as yet.

About 80 km. south-west of Baku a 3,000-bbl. well was completed at Pirsagat early in 1936, and at Nefte-Chala drilling and production were reported in 1934.

To the north-west of Baku, in southern Daghestan, oil seepages are known, gas between Derbent and Kayakent, and oil from mud volcanoes at Khosh Menzil 16 km. south of Derbent. Development of the Daghestan Ogny–Duzlack–Khosh Menzil area has been considered in order to supply gas to Derbent for industrial purposes. The gas is in the Maikop series, and also in the upper Chokrak-Spirialis beds at Khosh Menzil. At Berekei, north of Derbent, exploitation of oil and gas found in Chokrak and Maikop beds on a faulted NW.–SE. anticline took place in the period 1905–10, but the appearance of hot sulphurous waters stopped operations.

Oil indications have been found at Gubden, Izber-bash, and Iskir-bash in Chokrak beds. The 20-km. long Izber-bash anticline is considered more favourable than the more disturbed Iskir-bash structure, since the thick Sarmatian clays on the former may be expected to have preserved any oil present in the areno-argillaceous Spaniodontella and Chokrak beds.

The Grozny Region.

This region lies in the foot-hill zone of the northern flank of the Caucasus Mountains, about 450 km. north-west of Baku.

TABLE III

Stratigraphical Sequence for the Grozny Area (After Prokopov)

Pliocene	Apsheron	Sand, clay, sandstone, conglomerate.
	Akchagyl	Clay, sand, limestone, sandstone, conglomerate. 190–215 m.
	Local discordance.	
Upper Miocene	Meotian	Sandstone, sandy and calcareous clay.
	Upper Sarmatian	Grey clay and sandstone.
	Middle Sarmatian	Grey clay, shales with fish remains, sandstone, marl. Shales with Cryptomactra. Calcareous clay, ferruginous marl.
	Lower Sarmatian	Grey calcareous clay with interbedded yellow marls; grey shaly clay with dolomitized marl.
Middle Miocene. In east up to 1,000 m.; 250 m. or less in west	Spaniodontella beds	Grey clay with sandstone and dolomitic marl. Iron-stained clay with siderite. Oil-bearing sandstones. Hard limestone.
	Chokrak-Spirialis (II Mediterranean)	Grey and brown clay with sandstone and marl. Signs of oil in the sandstones.
Lower Miocene and Upper Oligocene. Up to 600 m.	Maikop	Grey and brown clay; black shaly clay with beds of sandstone and dolomite. Grey-blue clay with interbedded sandstone. Oil.
Middle and Lower Oligocene	Foraminifera beds	Light greenish marls with traces of oil.
Eocene. Up to 160 m.		Greenish and reddish marl; siliceous limestone (the latter has oil and solid bitumen).

The Grozny region has many oil and gas seepages, and production from hand-dug pits existed as early as 1823. The first gusher was completed in 1893 at a depth of 132 m.

The old Grozny field is an asymmetrical anticline, about a kilometre wide, and running WNW.–ESE. for 14 km. Lower Sarmatian beds outcrop on the axis, and dip faults mark out rich provinces as regards oil production. The southern flank dips at 30–50° and the northern flank is steep, overturned, or even broken by a thrust. Many wells on or near the axis of the fold give gas only, and gas reservoirs occur among the oil horizons in the Lower Sarmatian, Spaniodontella, and Spirialis beds. Often the gases are wet and at a temperature of 50° C. The main oil production is from a series of sandstones that are included in the clays and shales of the Chokrak beds. Within the last few years oil has been obtained from the sealed under-limb of the overthrust, probably from Spaniodontella and Chokrak-Spirialis beds [8, 1934]. Only in the western and middle parts of the field is this under-limb at reasonably accessible depths. In the east it lies at depths of 1,500–2,000 m. and its exploitation will call for skilful drilling.

Twelve to eighteen kilometres south-east of the old field is the new Grozny field, a less asymmetrical fold trending NW.–SE. Oil is obtained from 22 horizons within a shale series which is 530 m. thick. The field is under hydrostatic control, and the water, at temperatures of 76–87° C., is believed to move through a very deep syncline. An overthrust occurs in the western part of the field and production below it is thought to be possible.

Production at Voznesensk, north-west of Grozny, began in 1924, but development has not been extensive. South-east of Grozny the broad Benoi anticline lies in difficult country, which has hindered its exploitation. The fold runs WNW.–ESE. for 20 km. Dips do not exceed 16° on the northern flank and 30° on the south. Eastwards the fold flattens and passes into a monocline. Spaniodontella beds outcrop on the axis, and the tectonics of the Chokrak-Spirialis beds are somewhat complicated and differ from the general structure. Oil indications are first met in the Chokrak-Spirialis beds and increase downwards, a rich gusher having been completed in the Maikop beds in 1930. About 4 years ago the Malgobek field was discovered. This fold, which is 12 km. long, appears to be divided into eastern and western parts by a thrust which has left the oil sands sealed. Four rich oil horizons are reported.

The North-west Caucasus Region.

In this region Tertiary beds dip northwards from the Cretaceous hills and the oil occurs on monoclines, probably trapped in sand lenses or along unconformities. Production of oil has been established in a number of places, chief amongst which are Maikop (Neftianaia-Shirvanskaia), Kaluzkaia, and Ilsk.

At Maikop the Oligocene rests on Cretaceous beds, but to the west Eocene beds appear. The general dip of the beds is 8–15° towards N. 35–40° E. The main oil production at Maikop is associated with erosion valleys in the Foraminiferal beds, which are filled with conglomerates, gravels, and coarse sands belonging to the overlying Maikop beds. Oil is also found in sand lenses within the Maikop beds [10, 1923]. Shallow, monoclinal production of oil occurs at Ilsk in Maikop sand lenses and in a dolomitic horizon higher in the Miocene, the former giving a light oil and the latter a heavy oil.

In 1866 Russia's first gusher was completed at a depth of 21 m. at Kudako, 140 km. west of Maikop. Conditions there are similar to those at Maikop and the principal

production has been from Maikop beds at depths of more than 200 m. The Kaluzkaia field is on a monocline dipping north-east, the dips being steeper in the older beds—50° in the Cretaceous and Eocene, 35–25° in Chokrak-Konkski beds, and 15–12° in the Meotian. The chief horizon of heavy oil is in the breccia-like dolomites of the Mediterranean beds [14, 1932]. The Maikop and the bulk of the Foraminifera beds are also oil-bearing, the oil being in thin partings or small lenses of sand in sandy clays. Systematic exploitation of Kaluzkaia began in 1916, but the sporadic and irregular distribution of the oil has led to many wells being failures. It is interesting to note that in the Chokrak-Spirialis beds at Kaluzkaia are clay conglomerates with inclusions of Cretaceous rocks, probably the products of mud volcanoes which were active in Chokrak-Spirialis times. Oil has been produced at Khadigensk during the past few years.

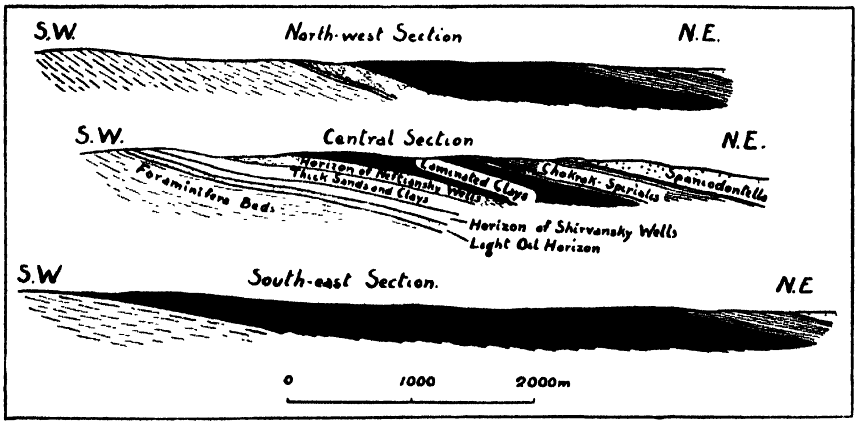

FIG. 6. Serial dip sections across the Neftianaia-Shirvanskaia field, showing changes in the Maikop beds along the strike. (*After Ulianov.*)

TABLE IV

Succession at Neftianaia-Shirvanskaia. (After Ulianov, with some additions)

Middle Miocene	Spaniodontella beds	Predominantly clay. At least 350 m. thick. Characteristic marl at base.
	Chokrak-Spirialis beds	Mainly clay; 200 m. thick. Masses of Chama limestone at base.
Lower Miocene and Upper Oligocene	Tarkhan beds	Clays. Absent beyond Primakovo ravine in the east.
	Maikop beds	Foliated clays with spherosiderite in upper parts. Main outcropping horizon. In the east it gradually replaces all the other Maikop horizons and attains 500 m. in thickness. Oil-well horizon with small lenses and partings of gravel and oil sands; 130–200 m.; wedges out east and west of central oilfield. Thick sands and clays, 80–120 m.; thin east and west.
	Light oil horizon	Grey clay, white marl, green foraminiferal clay; only present in parts.
Middle and Lower Oligocene	Foraminiferal beds	Foraminiferal clays with marls. 200 m. in west, 750 m. in east.

North-east of the Maikop area gas was discovered in the Stavropol district in 1910 while drilling for water [2, 1934]. The principal gas horizons are in the Sarmatian, but gas occurs also in Spaniodontella, Chokrak-Spirialis, and even Maikop beds. Sixty-five kilometres south-east of Stavropol a well encountered gas-bearing clays in Maikop beds. At Eisk on the eastern coast of the Sea of Azov gas horizons have been found in the Sarmatian.

The Taman Peninsula Region.

The Taman Peninsula is marked by many mud volcanoes. Although the production of oil from hand-dug pits was recorded in ancient history, the modern production of oil and gas has been but small. However, in recent years there has been a considerable amount of geological exploration in this area and nine folds have been studied. The lines of folding of the Taman Peninsula have a different trend from that of the Caucasus range, and the E.–W. and NE.–SW. directions correspond with those of the eastern part of the Kertch Peninsula. Often the folds are sharp and, according to Goubkin, diapiric structures are present.

The stratigraphical sequence in Table V is essentially that of Federov for the Varenikov region near the base of the peninsula.

TABLE V

Post-Tertiary	Alluvium, loess, mud volcano deposits.	
Pliocene	Nadrudni beds	Light coloured sands; light grey, non-calcareous clays. 100–165 m.
	Rudni beds	Grey, compact, non-calcareous clays; argillo-arenaceous, ferruginous crag. 110–170 m.
	Pontian	Light grey, calcareous clay; detrital limestones, sandstones, arenaceous clays. Local gas seeps. 165 m.
	Unconformity.	
Upper Miocene	Meotian	Greenish-yellow clay with thin calcareous sand and diatom ooze partings; soft and hard, dolomitized marls, and dark bituminous clays. Oil drops in marls. 70–75 m.
	Unconformity.	
	Middle Sarmatian (Cryptomactra)	Yellowish, unstratified, gypsiferous clays with soft and hard marl beds. 100–110 m.
	Lower Sarmatian	Yellowish calcareous, and purple-grey non-calcareous clays; partings of hard marls. 80–100 m.
Middle Miocene	Spaniodontella	Gypsiferous clay with numerous beds of soft and hard marls; minute drops of oil in marls. 85–100 m.
	Chokrak-Spirialis	Clays alternating with hard and soft marls. 115 m.
	Unconformity in places.	
Lower Miocene and Oligocene	Maikop beds	Purplish-grey and chocolate-coloured non-calcareous clays with spherosiderite. Sandstones at top. Up to 230 m. in thickness.
	Foraminiferal beds	Greenish siliceous clays, sandstones, and marls. Contain oil in some areas.

The Rudni (ore) beds are equivalent to the Productive series of the Apsheron Peninsula, but lack of cover has prevented the retention of any oil that may have been present in them. The poor production of oil on the Taman peninsula is attributed to the almost complete absence of suitable reservoir rocks in the dominantly clay series.

The north Varenikov fold is 3 km. long and 1 km. wide, its core being of Spaniodontella beds bordered by Sarmatian, and showing gas and oil seeps. The northern limb is overturned with some beds cut out. Cryptomactra beds outcrop on the crest of the southern Varenikov anticline. This trends WNW.–ESE. with both limbs dipping at 45–50°. Oil production is said to have begun in this area in 1933. On the Adagum anticline near Varenikov the first producing well was drilled in 1930, and commercial production was established in 1933. The Kessler structure is 2½ km. in length, with a core of upright Maikop beds. The dips increase with the age of the beds and the northern limb may be slightly overturned. It is apparently a diapir with oil in Maikop to Pontian beds. At Tiemriuk are gas seeps, principally connected with mud volcanoes, and wells have found gas in the Sarmatian.

The Kertch Peninsula.

Oil indications on the Kertch Peninsula are mainly in the eastern part and confined to Maikop and Mediterranean beds. On structures exposing the former beds oil seeps, gas shows, and mud volcanoes are common. The uplifts formed by Maikop beds are diapiric, the dips increasing on approaching the axis, where the beds are often vertical and crumpled. The bulk of the old wells were on the axial parts of the structures, but even at more favourable locations on the flanks large accumulations are not to be expected, for porous beds are generally lacking.

Great depth, lack of continuity, low porosity, and absence of oil at the outcrop are factors against commercial production of oil from the sandstones at the base of the Maikop series in the eastern part of the south-western plain. Oil indications, although less frequent, may be more significant in the Mediterranean beds, for at the base of the Chokrak and the Karagan in places there are sands and porous sandstones 3–10 m. and, exceptionally, 20 m. thick. The most common indications of oil are drops in hard marl partings, and sometimes the sandstones are oil-saturated.

On the NE.–SW. trending Chongelek anticline oil has been obtained from Mediterranean beds, and there is evidence of sufficiently thick porous beds in the Chokrak on the Chorelek anticline. The Babchik and Karama structures are viewed favourably for the same reason. On the Kop-Kochegen anticline the porous horizons of the Chokrak outcrop in the south-west and have lost their oil and gas, but it is possible that some oil may be preserved in the north-eastern part. The Spaniodontella and Chokrak beds outcrop on the Karalan, Temesh, Karmysh-Kelechi, and Burash anticlines. Hence they are deemed unfavourable in spite of seeps in the Maikop, for Arkhanguelsky and others do not consider the presence of commercial quantities of oil in the Maikop beds at all likely.

Some 27 structures have been examined within recent years, but the general lack of suitable reservoir rocks scarcely gives much hope for a large production of oil on the Kertch Peninsula.

Region South of the Caucasus Mountains.

On the southern flank of the Caucasus range many of the Mesozoic beds have bitumen. In the Kutais basin traces of oil have been reported from Eocene rocks at Korischi; from the Miocene at Anaklia, Supsa, Omparete, Maghele, Chotchklati, Guliani, Gurianta, Chapeturi, Mikhel-Gabriel, Samkhto, Jacobi, Narudja, and Notanebi [15, 1927]; the Upper Tertiary at Kvirili. At Notanebi asphalt is mined, whilst in the Ozurgety district oil occurs in beds equivalent in age to the Maikop and Chokrak, but at no point are large amounts of oil probable on account of the high dips and extensive faulting.

TABLE VI

Stratigraphical Succession in the Eastern Part of the Kertch Peninsula. (After Arkhanguelsky, Blokhin, and Osipov)

Post-Tertiary	Terrace deposits, alluvium, mud volcano deposits.	
Pliocene	Nadrudni	Sands and clays. 22–50 m.
	Cimmerian	Ore deposits—pisolitic grains cemented by a ferruginous clayey mass—in north-east and central parts. In south-east brown and greenish-grey clays alternating with ore seams. 22 m. Conformable on Pontian in synclines, but on anticlines may rest on any bed down to Pontian.
	Pontian	Green clays, fine sandstones, often grading laterally into limestones. Clays tend to occupy synclines. 20–30 m.
Upper Miocene	Meotian	Rapid changes in lithology laterally. Deep-sea greenish-grey, calcareous clay or light, soft marl; shallow-water Kertchenski shell limestone. Conglomerate marks boundary between upper and lower divisions. 35 m. of Hydrobia limestone at base in Kezenski syncline. 60 m. or more.
	Transition	Greenish clays.
	Upper Sarmatian	Light green or brown diatomaceous clays with rare, fine sand beds (up to 1 m. thick). On Kezenski anticline 26 m. of detrital limestone and loams alternating with marls containing land molluscs. 100–200 m.
	Middle Sarmatian	Argillaceous, marly rocks, bryozoan reefs or limestones. 8–20 m. At base clays merging into Lower Sarmatian.
	Lower Sarmatian	Clearly bedded dark grey or greenish-grey clays, often with marls and pure shell beds. This clay series, with that of Middle Sarmatian, is 370–450 m. thick.
Middle Miocene	Konkski horizon	Clays. 5–10 m.
		Clays with frequent interbedded slaty or pink marls. 100–140 m.
	Karagan	Greenish and brownish-grey clays with sandy streaks; often interbedded siliceous marls. In middle of series sand and sandstone beds 0·3–0·4 or even 2·2 m. thick. 100–130 m.
		Olive-green clays and interbedded marls. 40–50 m.
	Chokrak	In east clays and marls interbedded. 65 m. In west arenaceous-limy beds with rich fauna, in middle of clay. 150 m. The arenaceous-limestone facies rests on the eroded surface of lower clays which are entirely cut out in the north-west, where the arenaceous-limestone facies rests directly on Maikop beds.
Lower Miocene-Oligocene	Tarkhan	0·2 m. of black marl on Azov coast.
	Maikop beds	Closely laminated non-calcareous clay, dark grey concretions, pyrite and gypsum nodules. Gradual transition to Tarkhan.

A broad belt of seepages runs south-east for a considerable distance in the Kura Basin east of Tiflis. At Chatma 57 km. south-east from Tiflis oil has been obtained from the Sarmatian and a lower horizon on a faulted NW.–SE. anticline which is overthrust to the south-west. Oil has also been found in fair quantities at Jevat on the Kura, near Signakh, and at Ildokhany north-east of Tiflis, where there are oil seepages in Sarmatian and Oligocene beds.

The Trans-Caspian Region

Cheleken Island lies approximately on the axis of the Caucasus Mountains produced. There are many surface indications of oil, fossil mud cones are known, and the Persians practised mining at an early date. The first large well was drilled in 1904. Modern production is limited to the south-western part of the island.

The surface is covered by sands and brea deposits which mask the structure. According to Porfiriev [12, 1931] wells reveal the following sequence:

TABLE VII

Pliocene	Lower Apsheron	Compact marls.
	Akchagyl	Ash-grey arenaceous marls.
	Red series	Alternating grey and red marls with oil- and water-bearing sands.

The formations are more continental than on the Apsheron Peninsula, and the Red series, which is equivalent to the Productive series, is half desert, half lagoonal. The productive oil horizons are at the top of the Red series, deeper wells having encountered hot sulphurous waters. In the Upper Pliocene are several oil horizons which are not commercially important. The major axis of the structure exploited runs NW.–SE., with dips of 15–50° on the south-western flank and 18–20° on the north-east. There is much faulting parallel to the axis, and the steep side is involved in a fault trough, from which zone the best production is derived. Many of the faults contain ozokerite formed from ascending oil, and where oil has reached the surface brea deposits are present. The field is extensively water-flooded, some of the wells giving as much as 90% of water which is at an average temperature of 40–42° C., and at times attains 75° C.

Near the centre of the island is a large, faulted dome with the productive Pliocene denuded and Chokrak beds exposed. Many evidences of oil are present, and wells have yielded small amounts of oil.

Along the same general line and on the mainland east of the Caspian Sea is a basin of Tertiary beds cloaked by Quaternary, and possessing many oil and gas seeps and mud volcanoes. As on Cheleken Island the formations are more continental than they are at Baku, and Porfiriev [13, 1932] gives the following section for the Boya-Dag and Syrtlan-Li area:

TABLE VIII

Post-Pliocene	? Baku stage	Sands and clays; ferruginous sand at base.
	Sharp unconformity.	
Pliocene	Apsheron stage	Thick complex of clays; sandy clay series with globular concretions. Thickest on crests of the folds; thins quickly on limbs.
	Unconformity in places.	
	Akchagyl stage	Finely banded calcareous clays; fish remains and layers of volcanic ash.
	Red series	Coarse red sands alternating with calcareous clays. 300 m. of this series exposed on Syrtlan-Li.

The Red series is the age-equivalent of the Productive series of the Apsheron peninsula. Thirty-two kilometres south-south-west of Bala Ischem is the Nefte-Dag field, and 82 km. south-east of Nefte-Dag lies Boya-Dag. Each anticline is marked by a hill rising above the surrounding plain. The axis of Nefte-Dag runs ENE.–WSW. and the fold is faulted. Dips range 7–45°. Five wells were drilled in the period 1882–7, a little oil being found at shallow depths, and exploitation was resumed in 1927 when three dry holes were drilled. Later one was deepened a little and gave a good production of oil, while a second well on deepening came in at 35,000 bbl. per day. Early in 1934 a well was completed which is reported to have yielded 250,000 metric tons of oil in 16 days. Although prolific oil and gas horizons have been found, production in this area is erratic and is probably derived from the Red series.

Boya-Dag has dips of 40–50° on its northern flank and 15–20° on the south. There are many faults of which the throw diminishes from the centre to the periphery of the structure. The two faults bordering the central horst have maximum displacements of 400 m. Along the fissures are gas seepages and oil-impregnated sands, and at the western end of the fold mud volcanoes occur. The seepages diminish with distance from the zone of maximum fracturing. In addition there are dry oil sands, salt- and hot-water springs. For oil production it is thought that a deep horizon must be sought. Syrtlan-Li is a similar structure without oil seeps or dry oil sands, although gas has been found in a few places.

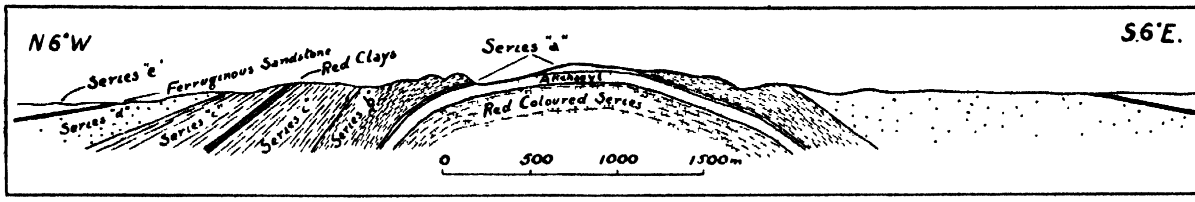

FIG. 7. Cross-section of Boya-Dag. (*After Porfiriev.*)

The Ferghana Basin

Madgwick [10, 1923] records that both the Oxus and Jaxartes valleys have oil shows from the Ferghana beds of the Lower Tertiary. Belts of seepages run along the northern and southern sides of the Jaxartes plain in the Namagan region, where these beds outcrop, and meet in the east.

TABLE IX

Succession at Maili Sai. (*After Golubiatnikov* [10, 1923])

First stage	(*a*) Brownish sandy clay and conglomerates. 1,000 m. (*b*) Brick-red clay, sand, sandstone, and conglomerates. 100 m. (*c*) Variegated sandy clay, sand, sandstone, and conglomerate; alternating blue, green, and red clay. 28 m.
Second stage	(*a*) Marl; red clay with partings of sand and sandstone. 59 m. (*b*) Limestone with Pecten; greyish-green calcareous clays and marls. 26 m. (*c*) Dark bituminous shales; concretions at top; fish remains. 33 m. (*d*) Sand and sandy clay; conglomerate at base. 60 m.
Third stage	Ferghana stage; limestone, marl, clay, sand, conglomerate; three thick limestones. 60 m.
Fourth stage	Sand, clay, and limestone; at base sandy clays, sands, and conglomerates. 150 m.

The oil-bearing rocks are probably Eocene in age and apparently contain oil only in the folds nearest the valley, and not towards the Cretaceous hills.

Within recent years 53 structures are said to have been discovered in this region by geological and geophysical

methods. Chimion gave about 25% of the Ferghana Basin's production in 1926, from Ferghana and Cretaceous beds on a narrow dome, which is overthrust a little to the north. Sel Rokho supplied the remainder of the production in 1926. In this field oil is obtained from Eocene and Cretaceous horizons on the northern limb of an east–west trending anticline. The first well on the Shor-Sou anticline was completed about 10 years ago. Again the productive horizons are in the Ferghana stage. It is also reported that the Ferghana beds cover large areas which have oil indications, south of Lake Balkash.

The Ural-Emba Region

This region, lying mainly between the Ural and Emba rivers, is regarded by some as one of the richest oil reserves in the world, but it is handicapped by its distance from large industrial centres and by poor transport facilities. In 1935 a pipeline to a refinery at Orsk was under construction. The production in 1935 was little different from that of 1916.

Oil seeps and asphalt deposits occur in at least 50 places, and at times the Caspian sands are impregnated by seeping oil. Over 300 salt domes are said to have been found in this general area, but Zavoico is sceptical as to their value, and observes that the fact that they are more faulted than those of the Gulf Coast region will render oil prospecting more difficult. Permian beds underlie the petroliferous area and are followed by Triassic or Jurassic beds unconformably.

TABLE X

Succession in the Issek-djal Area. (After Shumilin)

Post-Tertiary	Alluvium, clay deposits of the sors, Ancient Caspian sands. These beds are horizontal.	
Neogene	Middle and Lower Sarmatian	Sands and limestones. 10 m.
Paleogene	Greenish-grey clays with rare and thin partings of sandstones. 50–80 m.	
Upper Cretaceous	Senonian and Turonian	White chalk with green clays interbedded at base. At top and bottom of Turonian are 10–15 cm. beds of phosphatic rock. Thickness of Senonian unknown; Turonian 7–8 m.
	Cenomanian	Mainly sands with rare clay lenses. 200 m.
Lower Cretaceous	Albian	Rapid alternations of clays, sands, and sandstones. Clays dominant. Apparent thickness about 100 m.
	Aptian	Not exposed.
Upper Jurassic	Absent.	
Middle Jurassic	Dossor series	Violet-grey and yellow clays, grey sands, and coal partings 2–3 cm. thick. 200 m. exposed.

In the Ural-Emba region the Cenomanian, Lower Neocomian, and Middle Jurassic are subject to oil saturation. It is thought that the Permian may be the source of some, if not all, of the oil, for it is oil-bearing to the north of this region. According to Stutzer, there are five main anticlinal zones 150–200 km. long and trending in a northerly direction.

The principal field is Dossor, which lies on a north–south elliptical dome with Upper Cretaceous down-faulted on the west against Jurassic. Production began in 1910 and oil has been obtained from four horizons in the Jurassic, mainly at depths of 75–210 m. Oil is produced from several fairly shallow Jurassic zones on the Makat dome which is less faulted than Dossor, and small wells have found oil and gas at Tass Kuduk and Novo Bogatinsk, whilst valuable wells have recently been drilled at Guriev. Koschagyl is regarded as a typical salt-dome field. It is divided into northern and southern parts by a fault, seepages being especially common in the northern down-faulted part. The first well entered the Jurassic oil horizons at a depth of 290 m., and penetrated three sets of oil sands in 108 m. The productivity was highest in the lower sands. This field is viewed very favourably, since the Jurassic oil series is estimated to be 500 m. thick in this area.

The Issek-djal dome has a central down-faulted north–south block, the graben being filled with Tertiary and Caspian sands. The dome is terminated in the north by a cross fault, and both flanks have north–south faults. A secondary arch is present on the eastern flank. Although there are large seepages along the faults, the absence of outcropping oil sands and the presence of favourable tectonics on the eastern flank have led to its being regarded as a promising structure. At Iskine drilling began in 1932 1 km. south of a sharp salt structure. Some oil was encountered at four points from 22 to 147 m., and the Jurassic, with the main oil sands, was penetrated at a depth of 669 m. In the north at Djusa a good oil was found at shallow depths in 1914, and a little later oil was discovered at Karatchungul. Within the last few years oil has been found at Baichunas, Iman Kara, and Shubar-Kuduk.

West Ural Areas

In the Volga Basin in the vicinity of Samara, Kazan, and Sterlitamak, asphalt-bearing sands and limestones of Permian and Carboniferous age are common. The Sterlitamak area is said to be a rich oil reserve, oil having been discovered at Ishimbaevo in 1932. The productive horizons are limestones, probably of Carboniferous age. Early in 1936 70 wells had been drilled at Ishimbaevo of which 26 were flowing wells. Unfortunately the crude has a high sulphur content (2–5%). Eleven favourable structures similar to Ishimbaevo are now known in this region, which is about 128 km. from four trunk railways leading to European Russia, Siberia, and Turkestan, and is therefore considered of special value. During 1936 a refinery was being built at Ufa, about 80 km. to the north, and, pending the construction of a pipeline, oil is being transported by tank cars.

Some 500 km. farther north, in the vicinity of Perm, a well drilled for potash found oil and gas in commercial quantities. According to Zavoico it penetrated the following section:

TABLE XI

0·0–10·8 m.	Alluvium.
10·8–157·5 m.	Marls and gypsum; a few potash beds; gypsum increases with depth.
157·5–321·0 m.	Massive gypsum grading into anhydrite; towards base anhydrite is interstratified with black bituminous shales.
324 m.	As above; gas pockets and small oil saturation. Dark-grey cherty limestone; heavy oil and strong gas. Tentatively dated as Upper Carboniferous.

Zavoico suggests that the cherty limestone probably marks a major unconformity. In 1930 a well near Cherdyn found oil showings in the same beds at 557–9 m. Subsequently some 60 wells have been drilled to test the Chusovo area, but work has almost been abandoned for lack of satisfactory results, the limestones having been shown to be insufficiently porous. In 1933 production was established at Levshino north of Perm in Carboniferous beds,

and also in the Paper Combine territory 45 km. south of Perm.

Yet farther north oil indications are known for 250 km. along the eastern flank of the Timan range, from the Tsylma (a tributary of the Petchora) south-east beyond Ukhta [15, 1927]. The oil seeps are in the Devonian, which has 800 sq. km. of fairly rich oil shale, and in the Silurian. At Ukhta small wells have been completed in Devonian beds on an anticline. The Devonian consists of marls, bituminous shales, sandstones, limestones, dolomites, and gypsum. Over it lie discordantly Carboniferous limestone and marl, followed by Permian. The severe climate has limited development, for it is only during the period June to September that the ground is free from snow.

North Sakhalin Island

A small amount of oil has been produced on north Sakhalin Island. A belt of seepages runs roughly parallel to the east coast from Okha southwards. Furthermore, on the northern part of the western coast, on the Yrkry, a tributary of the Liangri, other oil seeps occur. Often the seepages are in the form of kir lakes, one of which covers 26,000 sq. m. to a depth of a few centimetres to a metre or more, in the Okha area.

TABLE XII

Stratigraphical Succession in Eastern Sakhalin
(*After Khomenkho* [9, 1931])

Quaternary		
Upper Pliocene	Supra-Nutovo series	Dominantly loose, fine sands, often cross-bedded and iron-stained yellow, yellowish-grey, rusty, bluish; medium coarse gravels, conglomerates; compact sandy, micaceous clays. Dips not over 15–20°. About 1,000 m. thick.
	Nutovo series	(*a*) Cross-bedded sandstones and interbedded conglomerates. (*b*) Compact, fine, bluish-grey, grey, and yellow-grey sandstones. (*c*) Grey and blue oil- and gas-bearing sands with interbedded sandstone and compact clay. Dipping at over 20°, usually 30–40°, occasionally 60°. About 2,700 m. thick.
Middle Pliocene	Ekhabi series	Light yellow, pinkish, dark-brown, grey, and brownish-grey medium-sized conglomerates; white, yellowish-grey, rusty, pale greenish-grey sandstone with mica and a few pebbles; plant remains. 850 m. thick in the Katangly district.
Lower Pliocene	Okobykai series	Sandy clays.

The folds along the east coast run mainly north–south. The Okha anticline stretches 5 km., principally in a north–south direction. Its western flank dips at 6–20°, the eastern flank at 10–85°. The seemingly greater thickness of the oil series on the eastern flank has been suggested by Kosyguin as possibly the result of overthrusting and imbrication. Two uplifts occur along the crest of the structure, and production is from that north of the Okha River. The first well, drilled in 1889, did not find much oil, but in 1921 three wells on the western flank found fairly rich shallow oil. Further wells have been drilled by Japanese and Russian companies in this, Sakhalin's largest field.

The Ekhabi anticline runs 6 km. north–south, with westerly dips of 20–50° and easterly dips of 15–40°. There are two big faults parallel to the axis, and along these oil seeps occur. No rich oil horizon was found by wells 226 m. deep. The Paromai-Kydylani fold is about 16 km. in length. Dips are generally less than 40°, but may attain 70°, and the steeper western limb is overturned in places. There is a series of east–west faults. Oil seepages are confined to the basal parts of the Ekhabi series and the top of the Okobykai. The long Nutovo anticline has dips of 60–70° on its western flank and 80° on the east. In the lower course of the Nutovo River is a small overturned fold with a fault extending north and south. Along this fault are many oil seeps and gas eruptions. A small well on the eastern flank found a little oil at 30 m., and a second well reported much oil at 80 m., whilst on the main anticline a well encountered some oil and much gas at a depth of 879 m. There seem to be seven oil sands, but little development has taken place. Oil seeps occur on a fold at Uini. To the south, in the region of the Imtchin and Uiglekut rivers, are two anticlines on which are oil-sand outcrops in the middle and bottom of the Okobykai series. Both anticlines are almost symmetrical, and the eastern Noglik-Katangli structure has two elevations on its crest.

On the western coast of Sakhalin, in the neighbourhood of the Yrkry seeps, the succession is as shown in Table XIII.

TABLE XIII

(*After Gedroitz*)

Post-Pliocene	Terraces and sands difficult to distinguish from Tertiary beds.
Tertiary	Mainly cross-bedded sands; some clays. Upper 150 m. nearly pure sand. Clays (mainly soft) predominate in the next 100 m., with some brown coals. 120 m. of beds with sands predominant; Yrkry oil seeps in the upper part. 2nd. coal series with hard shaly clays; at least 75 m. thick.

A fossil fauna is lacking in these formations, and the plant remains are badly preserved. Hence it has not been possible to correlate these, the Liangri rocks, with the oil series of the east coast. Their appearance is more youthful, but that may be a consequence of their having suffered less disturbance. Two broad gentle anticlines are known in the area. Their axes run north–south. The core of the western anticline reveals the oil series, and that of the eastern fold the lower clays. The Yrkry seeps are restricted to the western limb of the latter fold.

Climatic conditions in north Sakhalin are severe and not very favourable for oil production. The sea is open for only 4½ months of the year, thus calling for large oil-storage facilities if the fields are developed extensively.

Other Areas with Indications of Petroleum

Oil and gas or other indications of petroleum have been discovered in various other parts of the U.S.S.R. Gas-bearing beds have been observed in 30 localities in the Melitopol-Bierdianesk area north of the Sea of Azov when wells have been sunk for water. Eleven gas horizons were found about 210 m. deep in the Middle Sarmatian near Bierdianesk. Within Astrakhan city, at the mouth of the Volga, two gas horizons were encountered in Caspian beds at depths of less than 200 m. To the north in the Dergachevsky region (on the borders of the districts of Samara and Saratov) two shallow persistent gas horizons occur in the Akchagyl. Oil sands have been reported in the Permian near Volgoda and along the Sukhova River, but they are little prospected and undeveloped.

In Central Asia wells have found oil at Khaudag in limestones of Paleocene age and in the Jurassic, and oil was proved at Khanabad Sai in 1934. Fifty-three other

structures with considerable showings of oil are reported from the same general area. On the south-east coast of Lake Baikal are oil and gas seeps and ozokerite deposits, in addition to submarine seepages. Here, and also on the north-west coast, wells have encountered small flows of oil. A well has been drilled at Cape Nordwick, and indications of petroleum have been noted at the mouth of the Anabar. Oil is reported along the Tavda, at Surguta, and at the mouth of the Khatanga; at the mouth of the Lena, on the Taimir Peninsula, on the east and west coasts of Kamchatka, and on Novaya Zemlia.

Many of these areas, if they do contain important accumulations of oil and gas, are severely handicapped by their geographical position—great distance from industrial centres, and the coldness of their climates. Their development will be a matter of some difficulty. It is, therefore, not surprising to find that the U.S.S.R.'s increased production has been obtained chiefly by the further development of the regions first exploited, in particular the Caucasian region (Apsheron, Grozny, and Maikop), where the discovery of deeper productive horizons and of new structures, and the utilization of the less prolific horizons, has enabled the total production of oil to be more than trebled in the 10-year period ending 1935.

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ROUMANIA

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Oil and gas in commercial quantities are obtained from three main areas in Roumania: the Transylvanian basin, the southern sub-Carpathians, and the eastern Carpathian Flysch zone (Bacau district). As yet only gas has been found in the Transylvanian basin, and in recent years the Bacau district has given but about 1% of Roumania's oil production. The southern sub-Carpathian zone may be divided into two parts, of which the Buzau area provides almost 1% of the present annual production, and the rest of the country's output is derived from the Dambovita and Prahova districts. In Transylvania gas seepages have been known on some of the domes for 200 years, and a commission considered the utilization of gas from one of them a century ago, but the first gas well was not completed until 1909 while attempting to locate potassium salt masses by prospecting drilling (Gardescu [2, 1934]). As early as 1650 oil was exploited by shafts at Lucacesti in the Bacau district, whilst the first wells were drilled at Mosoarele in 1860. Exploitation in the Prahova district dates from the excavations of the second half of the sixteenth century. There the first wells were drilled in 1863, but drilling only became important 30 years later (Pizanty [9, 1933]).

Fig. 1. Oil and gas areas of Roumania.

The Transylvanian Basin

The gas is produced from the Sarmatian, and some fifteen productive zones have been developed in 1,200 m. of beds. These gas zones are somewhat irregular in position. It is hoped that gas may be obtained from the Middle and Lower Miocene where suitable reservoir rocks exist.

On the fringes of the Transylvanian basin oil seepages are found near salt springs in the Lower Miocene as well as in the Oligocene, Eocene, and Cretaceous. Within the basin the folds trend generally north-south, being broad and widely spaced in the centre of the basin, and steepening towards its margins, where they may be overturned or even overthrust outwards. Most of the marginal folds have a salt core, and salt cores are thought to be present at depth in the gas-producing areas of the centre. West of a line through Dos, Kolozs, Torda, Nagy-Enyed, and Vizakna, and east of a line through Szasz-Regen, Szovata, and Kohalom, gas in quantity is not expected because of the extent of disturbance of the structures.

Forty-three domes are known, of which thirteen are deemed unfavourable due to absence or extensive erosion of the

Table I

Stratigraphical Sequence in the Transylvanian Basin

Quaternary	Terrace deposits; alluvium; loess near base.
Pliocene	Mainly fresh-water clays, sands, and lignites.
Miocene	Sarmatian. Scattered lakes were left by the Lower Miocene sea. In some the water became fresh. Sandstones and conglomerates were deposited on their margins and marls towards their centres. Upper Mediterranean or Helvetian has alternating beds of grey, poorly cemented sandstones, gypsum, and volcanic ash. The Lower Miocene submergence led to the formation of the basal conglomerates (Lower Mediterranean or Burdigalian).
Oligocene	Calcareous clays, red clays, poorly consolidated sandstones, and some conglomerates. In the north-west the upper conglomerates have beds of brown coals; in the south-west are Upper Oligocene brown coals.
Eocene	Two alternating series of red clays, gypsum, and nummulitic limestones; the upper limestone includes a few fresh-water beds.

Sarmatian; five lack closure in the upper beds, but may have closure at depth; eight have been proved, and the rest are viewed favourably. Methane springs are known on some of the domes, in addition to salt-water and hydrogen sulphide seepages and mud volcanoes. The productive domes are Sarmasel, Moinesti, Sincai, Saros, Bazna, Nades, Daia, and Copsa Mica. At Sarmasel a deep gas horizon has been found in the Mediterranean, and some gas is obtained from the Pliocene at Nades and Copsa Mica. The gas produced is dry and contains 95·46–99·1% of methane.

Bacau District

TABLE II

Stratigraphical Sequence in the Bacau District

QUATERNARY		Terrace deposits.
PLIOCENE	Pontian	Dominantly marls, clays, and a few fine sand intercalations.
	Meotian	Alternations of sands, marls, sandstones, and limestones. Transgressive on to the Flysch in the Comanesti-Moinesti basin. The predominance of sand gives oil reservoirs at Moinesti. About 300 m. thick.
MIOCENE	Sarmatian	Marls, sands, conglomerates, and micaceous sandstones.
	Upper Salifère	*Poduri Beds*: predominance of sands and sandstones, with dacitic tuff intercalations in upper part; rare conglomerates. 100–150 m. thick. *Campeni Beds*: mainly clays, marls, and gypsum; rare sand intercalations (oil-bearing at Campeni). 400–500 m. thick.
	Lower Salifère	*Antal Beds*: upper part red and green marls and sandstones interbedded; lower part thin conglomerates, gravels, and sandstones. About 300 m. thick.
OLIGOCENE		*Salt Horizon*: clays, marls, and sandstones; rich in gypsum and salt; dark coloured and bituminous; conglomerates.
		Kliwa Sandstone: thick bands of sandstone separated by thin marls, but marls become thicker and sandstone beds thinner towards the top of the formation. *Menelite Shale Group*: white sandstones with efflorescent sulphates; characteristic bituminous shales with gypsum and fish remains; brown calcareous marls and thick sandstone intercalations. The marls and shales indicate anaerobic conditions, and are often silicified into lenticular masses.
EOCENE		Micaceous, jointed, calcareous sandstones (Moinesti Sandstones) with ripple marks and hieroglyphics; hard sandstones and conglomerates; grey, red, and green marls. Small amounts of oil. 350–400 m. thick.

The marginal Flysch of the eastern Carpathians has been thrust over the Salifère as a sheet 3–4 km. wide, and folding continued until Pliocene or later times. In the Bacau district, in addition to the marginal faults of the Carpathians and the sub-Carpathians, there are two other important lines of faulting: (1) the Trotus fault running from Onesti to Barlad; (2) the Tazlau fault. It is along these lines of faulting that the petroliferous areas are found (Sergescu [11, 1930–1]).

Solontu and Stanesti lie respectively on the east and west of a structure in which two sheets of Oligocene beds have been thrust over Antal beds and arched, with Upper Salifère partially cloaking the overthrust beds. Five oil sands are found in the Oligocene series. Wells range up to 500 ft. in depth, and their poor production is improved by shooting. At Tetcani a small amount of oil is obtained from sands and conglomerates in the Campeni and Antal beds. Oil seepages have long been known at Tetcani and in the Vallée Sarbilor to the north-west, and in both places oil has been exploited by shafts.

Moinesti shows inverted Eocene and Oligocene, contorted and overthrust eastwards on to the Salifère. Meotian and Pontian have been deposited over the Eocene. Near the thrust the Eocene outcrops, and along with the Oligocene it has been worked by shafts. Water troubles have hindered exploitation of the Meotian, but about 150 m. below its top are a gas sand 25 m. thick and oil sands. The Meotian is productive in the southern part of the field. Below the Pliocene the Eocene yields a little oil, and oil has also been encountered in the Oligocene at depths of more than 900 m. At Lucacesti oil is obtained mainly from the Oligocene. Wells show the Oligocene to have overridden the Salifère eastwards at Tazlau, and oil production is from the Oligocene. The Kliwa sandstone yields oil at Zemes, where the beds are overturned, contorted, and fractured, and the Eocene, which partly covers the Oligocene, shows traces of oil. The wells are long-lived small producers due to the low porosity of the rocks. In the north, production of water with the oil is increasing.

The Campeni field lies east of the Tazlau fault, and in it oil is found in the Campeni and Antal beds. The oil is believed to be secondary and hopes are entertained of Oligocene production beneath the Salifère. According to Sergescu [11, 1930–1] a small amount of good-quality oil was produced from the Sarmatian at Casin. Attempts to exploit oil in the Oligocene, and possibly in the Eocene at Dofteana, by means of inclined galleries and a shaft were abandoned for want of capital, although some oil sands were met. At Mosoarele ozokerite veins occur and the Oligocene has been found productive beneath the Eocene.

A little oil has been found in a number of other places associated with this region of complex tectonics. In these, and in the fields already mentioned, oil has been obtained from numerous pits, about 1 m. square and as deep as 200 m., as well as from wells.

The Southern Sub-Carpathians

The Buzau District.

This lies east of the main Roumanian oilfields. Its principal feature is an anticlinal structure (Arbanasi) running NNE.–SSW., and traceable for almost 30 km. Elevations occur on the crest at Beciu and Berca. The structure is steep, asymmetrical, and probably faulted near its crest, along which mud volcanoes are known. The Meotian is exposed in places and contains the chief oil horizons. Some oil is found in the Sarmatian. At Sarata-Monteoru is a steep and slightly overturned fold with a reversed fault. The Sarmatian outcrops and oil production is obtained from the Meotian and the Sarmatian. There are several wells and, in addition to pits, shafts with drifts and inclines have been made in the oil zones.

TABLE III

Generalized Stratigraphical Succession for Southern Sub-Carpathians

PLIOCENE	*Levantine*: marls, clays, sands, lignites, coarse sandstones, and conglomerates. Fresh-water deposits. 500–700 m. thick.
	Dacian: coarse sandstones, clays, sandy marls, and lignites. Fresh-water deposits. 300–450 m. thick.
	Pontian: marine clay and marls; sandy towards the top. 650–800 m. thick.
	Meotian: coarse sandstones, continental marls, fine, brackish-water sandstones and fresh-water sandstones, marls and sandy marls. 330–580 m. thick.
MIOCENE	*Sarmatian*: marls, clays, sandstones, conglomerates, and limestones. 350–450 m. thick.
	Tortonian: marine to brackish marls, sandy marls, and limestone. About 100 m. thick.
	Upper Helvetian: grey sandy marls, sandstones, dacitic tuff, and salt.
	Lower Helvetian: grey and red marls with gypsum. Total thickness of Helvetian about 600 m.
	Burdigalian: conglomerates, sandstones, and sandy marls. 100–200 m. thick.
OLIGOCENE	Sands, sandstones, conglomerates, shales and black bituminous shales or marls (Cornu beds), gypsum, and salt. (The Helvetian, Burdigalian, and Cornu beds are lagoonal deposits.)
EOCENE	Shallow marine deposits, conglomerates, sandstones, black shales, marls, and limestones.

The Dambovita and Prahova Districts.

In going southwards in this main oilfield area there is a general change in the type of producing structure; from the overthrusts of the north which resemble the structures of the Bacau district, through uplifts with salt cores penetrating to, or almost to, the surface, to more simple anticlines which may or may not show salt masses at depth. There is a tendency for the fields to lie along lines of uplift which fork or lie *en échelon.*

Bustenari is connected with the main line of dislocation in the north. The Oligocene has been thrust southwards over the Salifère, and the southerly dipping Meotian overlaps on to the Oligocene (Slomnicki and Meyer [12, 1925]).

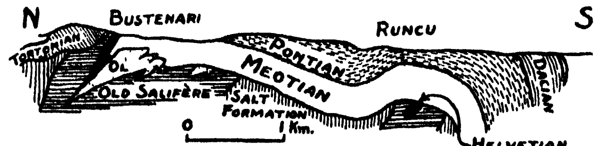

FIG. 2. Bustenari and Runcu. (*After Krejci.*)

Good production is found at comparatively shallow depths in the Oligocene, and oil is also obtained from the Meotian down to depths of 1,000 m. Campina lies immediately south of a line along which the Salifère has been thrust steeply to the surface against the Meotian. A second mass of salt at a shallow depth has folded the Meotian which gives prolific production from the southern flank of the structure. Oil is also found in the Dacian.

To the south is situated the field of Runcu, a simple elliptical dome with its major axis east-west, and yielding oil from the Meotian. West of this dome is Chiciura, where oil occurs in the same horizons.

Around the Moreni salt upthrust are the fields of Pleasa, Stavropoleos (north), Bana (north-east), Piscuri (east), Cricov, Tuicani, and Pascov (south). The Levantine forms the surface beds, and the strata are thinner on the northern than on the southern flank (Gheorghiu [3, 1931]). The salt overhangs considerably on its southern margin. A number of oil zones have been exploited in the Dacian on the south, but they are not generally productive north of the salt (some oil is obtained from the Dacian at Bana). Their importance and productive area increase with depth, and the upper ones only yield oil near the salt. The 'Gros', '6-metre', and '14-metre' sands are water-flooded over

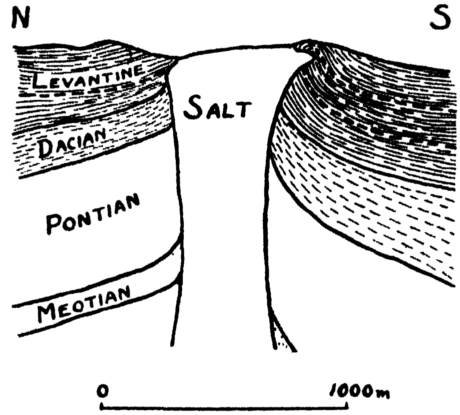

FIG. 3. Moreni: showing overhanging salt. (*After Krejci.*)

much of the area, and the most important Dacian horizons, the Moreni and the Drader sands, run together at the eastern and western ends of the field. The Drader sand is productive at Piscuri. On the northern flank the 1st. Meotian sand is thin but richly impregnated with oil. The 2nd. sand is poor, and although the 3rd. sand has been found to contain oil, usually it is charged with salt water. The 1st. Meotian sand on the southern flank yields oil, but the 2nd. sand is poorly developed. The intermediate gas sand is under very high pressure and presents drilling difficulties. The bulk of the Meotian production is from the 3rd. sand.

The Ochiuri field lies west of Moreni. A small salt upthrust is present. The Levantine is at the surface on its northern edge, whilst the Dacian is the main outcropping

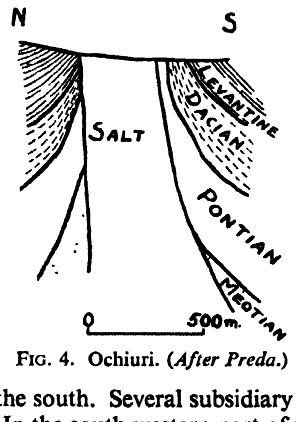

FIG. 4. Ochiuri. (*After Preda.*)

formation on the south. Several subsidiary folds run from the salt mass. In the south-western part of the field (Preda [10, 1929]) is a north-south line which separates a western area, where the Drader is unproductive, from the eastern area where it is productive. The Meotian production is only moderate. East of Moreni is Filipesti, a broad, long anticline with no known salt core. The upper Dacian outcrops and the Meotian alone gives oil.

A salt core comes to the surface at the complicated

western end (Baicoiu) of the Baicoiu-Tintea structure, where the Dacian and Meotian are productive. The eastern part of the Gura Ocnitei field has an outcropping salt mass. In this, the old part, the southern flank is the more important because of the Dacian production. The sands above the Drader are watered. The 1st. Meotian is usually poor, but the 2nd. sand is extensively exploited. The 3rd. sand has only a low gas pressure (Mircea [7, 1931]). The salt mass has a NE.-SW. trend and is at depth in the western extension of the Gura Ocnitei field. Two surface faults are connected with the underground salt mass. On the southern flank the upper oil sands of the Dacian are water-flooded at many points, but the Moreni sand is exploited in some parts. The Drader is the richest and most extensive horizon in the Dacian. Oil is obtained from the 1st. Meotian sand, but not from the 2nd. sand; the intermediate sand contains only gas, and salt water is present in the lower part of the 3rd. Meotian. On the northern flank the rich 1st. Meotian and the 2nd. sand are produced together. Near the salt the 3rd. Meotian sand has salt water in its lower part as on the south. The thickness of this sand diminishes westwards.

Floresti is a further example of an intrusive salt mass. At depth it may be connected with the Tintea-Baicoiu structure. Within a short distance of where the salt ceases to be seen, the Dacian no longer yields oil.

Proceeding southwards along the Teleajen the progressive change in structural type is seen. In the north at Valeni de Munte Eocene and Oligocene rest on Lower Salifère (Basgan [1, 1930]), and there the earliest exploitation took place. On the northern flank of the Gura Vitioarei-Copaceni structure the Oligocene sandstones show inspissated oil at the surface. They have been upthrust into contact with the Meotian, and the latter is cloaked by the Pontian. Oil has accumulated in the Meotian and is obtained at quite shallow depths. Some wells pass through the Oligocene to it. At Scaiosi, 1·5 km. south of Copaceni, the salt is 96 m. below the surface. It has thrust up Meotian, Sarmatian, and Mediterranean beds as a fractured east-west structure. On the northern flank little oil has been found in the Meotian, for that series lacks cover. On the southern flank the Meotian outcrops in places, and the upper beds have been water-flooded, but the basal beds are well preserved and good-quality oil has been obtained 125 m. down in the Meotian. The Boldesti structure lies still farther south, and there no salt is known. It is a broad, elongated dome with its major

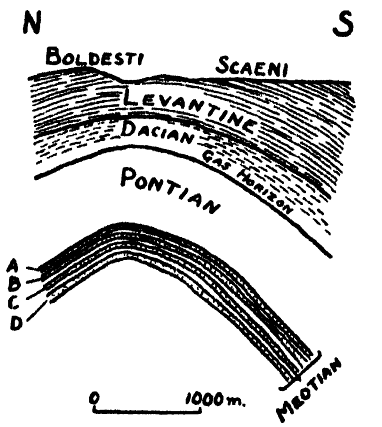

FIG. 5. Boldesti. (*After Patriciu.*) A = Gas zones. B = I Meotian oil complex. C = Intermediate Meotian oil complex. D = II Meotian oil complex.

axis running about N. 70° E. for 13 km. On it are Boldesti and Scaeni, and Harsa in the east. No faults are known, and the northern flank is the steeper. Only the Levantine outcrops. The beds are considerably thicker than in other fields (Iscu [4, 1931]). A little gas is encountered in the Dacian, but no oil. The Meotian is the productive formation, and below four high-pressure (as much as 200 atm.) gas zones are two important oil horizons, the first being 1,450–1,550 m. deep on the crest.

Aricesti is a dome on which the Dacian yields dry gas and a little oil at depths of about 550 m., and oil is obtained from the Meotian at 1,650–2,300 m. The Meotian is in the course of development.

The long, narrow anticline of Ceptura extends NE.-SW. for about 5 km. Pontian outcrops on the crest, and in it a gas bed was found 250 m. above the Meotian. Two important oil zones occur in the Meotian and give a highly paraffinous oil. The productive part of Ceptura seems to continue westwards towards Urlati-Valea Calugareasca, which lies south of the Boldesti-Harsa dome (Mihalache [6, 1931]).

The fields mentioned by no means exhaust the list of those which are productive. Until recently the bulk of Roumania's oil has been obtained from structures in or near the foot-hills of the southern sub-Carpathians. Geophysical work has been carried out on the great plain south of the foot-hills during the past few years, and in 1934 four wildcats were completed in the gravel-covered plains (Penny [8, 1935]). The Bucsani well, 10 km. south of the foot-hills, reached the Meotian at 1,500 m. and found oil. A subsequent well would seem to show that the anticline is broad and several kilometres long. The Dragomiresti well in the Dambovita valley met the Meotian at a depth of 1,800 m. and found high-pressure sands in it, but the production was mainly of water.

The age of the upthrust salt and the oil-source beds are two controversial points in Roumanian oil geology. Voitesti [13, 1926], basing his ideas on the ages of fragments found in the breccias associated with the edges of the salt masses in some places, has gradually lowered the source of the salt down the geological column, until he suggests that it is part of the earth's original crust condensed from a vapour. At various times solution and recrystallization have separated the different salts and deposited them in depressions of the continental areas of the earth's crust. Thus most salt should be attributed to the older formations. But the old fragments have not necessarily been carried up from great depths by the salt. Early Tertiary erosion must have exposed much older rocks, of which fragments would appear in Tertiary conglomerates, and it is possible for these to have been reworked. Pustowka finds that the salt masses are confined to regions where the saliferous Aquitanian, Burdigalian, and Helvetian formations occur, and so assigns an Upper Oligocene and Miocene age to the upthrust salt and the accompanying clay and marl. Bertrand and Joleaud hold the same view, and Mrazec and Krejci put the age as Aquitanian. Posepny, Koch, and Böch have considered the salt of the Transylvanian basin as being intercalated with the marls of the Helvetian.

The Aquitanian shales—black, sulphurous, and highly bituminous marine shales—are believed by Krejci to be the exclusive source of Roumanian oil. They attain thicknesses of as much as 500 m. in southern Roumania between the saliferous horizons of the Oligocene and the Miocene, and all the oil accumulations show contact, connexion, or at

least proximity with these. Macovei has expressed the opinion that the Menelite shales of the marginal Oligocene and the black Barremian (Lower Cretaceous) shales of the interior Carpathian zone are typical oil-source rocks, and, according to Voitesti, all divisions of the stratigraphical series from the Lower Cretaceous to the Upper Pliocene, with the exception of the Senonian, Pontian, and Levantine, contain more or less well-developed source beds. Mrazec points to the Salifère as the main source series, and the Oligocene and Eocene may have been the sources of small amounts of oil. Thus, complete agreement on the question of source beds is lacking, but the general tendency is to favour those Oligocene or Lower Miocene beds which most closely comply with the conventional conceptions of oil mother rocks. A satisfactory solution of the problems of source rocks and oil migration, when reached, must explain why the Dacian seems to give only gas on structures where it is not faulted or intruded by salt, e.g. Boldesti and Aricesti, and the general increased productivity and areal extent of oil sands with greater depth in a single field.

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ALBANIA[1]

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THE main oil occurrences of the country are associated with the Tertiary strata around the Adriatic shores. The Albanian coastal belt is subdivided into two parts: the western part, mainly of Neogene strata, is block-faulted rather than folded. The eastern is closely folded and forms a series of tectonic units mainly composed of Palaeogene Flysch, with calcareous basement rocks in the cores and with narrow belts of Neogene preserved in the zonal depressions.

The direction of folding maintains its Dinaric character (Nowack [3, 1930]), i.e. NNW.–SSE., though this is disturbed in some regions by large transverse flexures. These flexures are associated with subsidence phenomena.

I. Neogene Oil Occurrences (Fig. 1)

The marginal Neogene frequently covers buried Eocene structures which have a Cretaceous limestone basement and flanks composed of Flysch beds which were eroded in pre-Miocene times. In contrast with the frequent buried anticlinal structures, the overlapping Neogene maintains its synclinal attitude. The marginal Neogene sediments are of mixed character, being of salt-, brackish-, and fresh-water types. They correspond to an extensive Middle Miocene transgression, with later post-Miocene oscillations. The unconformities, which follow the pre-Miocene tectonics, are seen towards the eastern margins.

The brown coals are intimately related to the petroliferous strata and they very often take the place of oil sands. Lignitiferous bands of Miocene frequently become petroliferous, though retaining all their other characteristics. The presence of bituminous sands containing organic vegetable matter is very suggestive. The Albanian lignites belong to the asphaltic-pyrobitumens and frequently change into real asphaltites.

Kuchova Oil-pool (Fig. 2). This field is in an angular Neogene embayment following a transverse flexure of the Palaeogene folds. Two main unconformities are present: the upper at the base of the Pliocene and the lower which belongs to the Tortonian. A buried Flysch anticline, eroded to the basement limestones, is directly covered by overlapping Miocene. The edges of the Miocene syncline are upraised, faulted, and even locally overthrust by the Flysch. The oil-bearing strata are subdivided into three complexes: (1) Kuchova—dark grey clays with small sand-lenses; fresh-water fauna; oil impregnations of sands and sandy clays only locally productive. (2) Gorani—grey and variegated clays with numerous sand-lenses, brackish- and fresh-water fauna; numerous sand-lenses well impregnated and productive. (3) Driza—variegated clays with rare and only locally impregnated sand-lenses; brackish fauna prevails. On the top of 'Driza' a layer with Ostrea is present and forms an excellent key-bed therein.

The 'Driza' belongs to the Upper Tortonian. The lower part of the 'Gorani' may also be thus classified. The 'Kuchova' is Upper Miocene.

The oil is asphaltic (sp. gr. 0·930–0·940) with a high percentage of aromatic fractions and a low content of medium boiling-point fractions. Sulphur content is 3–4%. The formation is lenticular in character and production is obtained from individual lenses. The same holds for the brines which are disseminated through the 'Gorani' and 'Driza'. No edge-water has been found. The synclinal depressions of the pool are the best production zones. In the neighbourhood of the buried massifs the oil saturation diminishes considerably.

Initial productions are from 5–10 tons daily but more is obtained from the good sectors of the pool, and this production is apparently constant. Some gushing has occurred. The gas pressures are low and emanate from single sands.

Pahtos-Selenitza Oil-bearing Belt (Fig. 3). Tectonics: a marginal belt transversely faulted, with a central calcareous massif (Selenitza) unconformably covered by Miocene deposits. Local unconformities extend up from the lower Miocene. The Pahtos pool is a monoclinal block uniformly dipping towards the north, composed of Tortonian and Helvetian oil-bearing beds, with an abundant marine fauna, unconformably covering the Schlier (Lower Burdigalian and Aquitanian).

The Selenitza oil shows consist of bituminous oil sands partly weathered, Upper Miocene and Tortonian in age. Fluid oil has been found down-dip towards the north. Between Selenitza and Pahtos a depression exists which is completely covered by the Pliocene. The Selenitza oil shows are similar to those of the Kuchova structure, but the strata are more elevated and therefore more eroded and the oil is residual in character. Secondary asphaltic veins and pockets exist near Selenitza in the Lower Pliocene (old seepages weathered and oxidized). The oils of the belt are asphaltic and sulphurous (sp. gr. 0·940–0·990 and more).

Other oil shows are distributed in the vicinity of the Kuchova pool (Pekisti) and of Selenitza (Greshitza).

II. Palaeogene Oil Shows

Oligocene. These comprise bituminous sands and asphaltic impregnations of fossiliferous sandstones in several localities near Elbassan. The palaeogeographic conditions are, in these cases, similar to those of the Selenitza-Pahtos belt (buried pre-Oligocene structures with eroded Eocene limestone basement).

Middle Eocene. The lowest strata of the Palaeogene Flysch are oil impregnated in several localities. Their tectonics correspond to anticlinal flanks with their calcareous core exposed. Near Valona (Drashovitza) small initial productions of oil (average sp. gr. 0·935) have been obtained. Similar oil impregnations of some extent exist in the neighbourhood of Berat.

The general stratigraphic positions of all the oil shows in Albania are as follows:

Pliocene. Secondary asphaltic veins in the neighbourhood of the oil-bearing basement.

Upper and Middle Miocene. Asphaltic oils near the edges of the Miocene coastal transgression; this is the main oil-bearing formation. Deposits are of the Mediterranean type (Zuber [1, 3–5, 1935–1937]).

Lower Miocene—Oligocene and Upper Eocene (Schlier

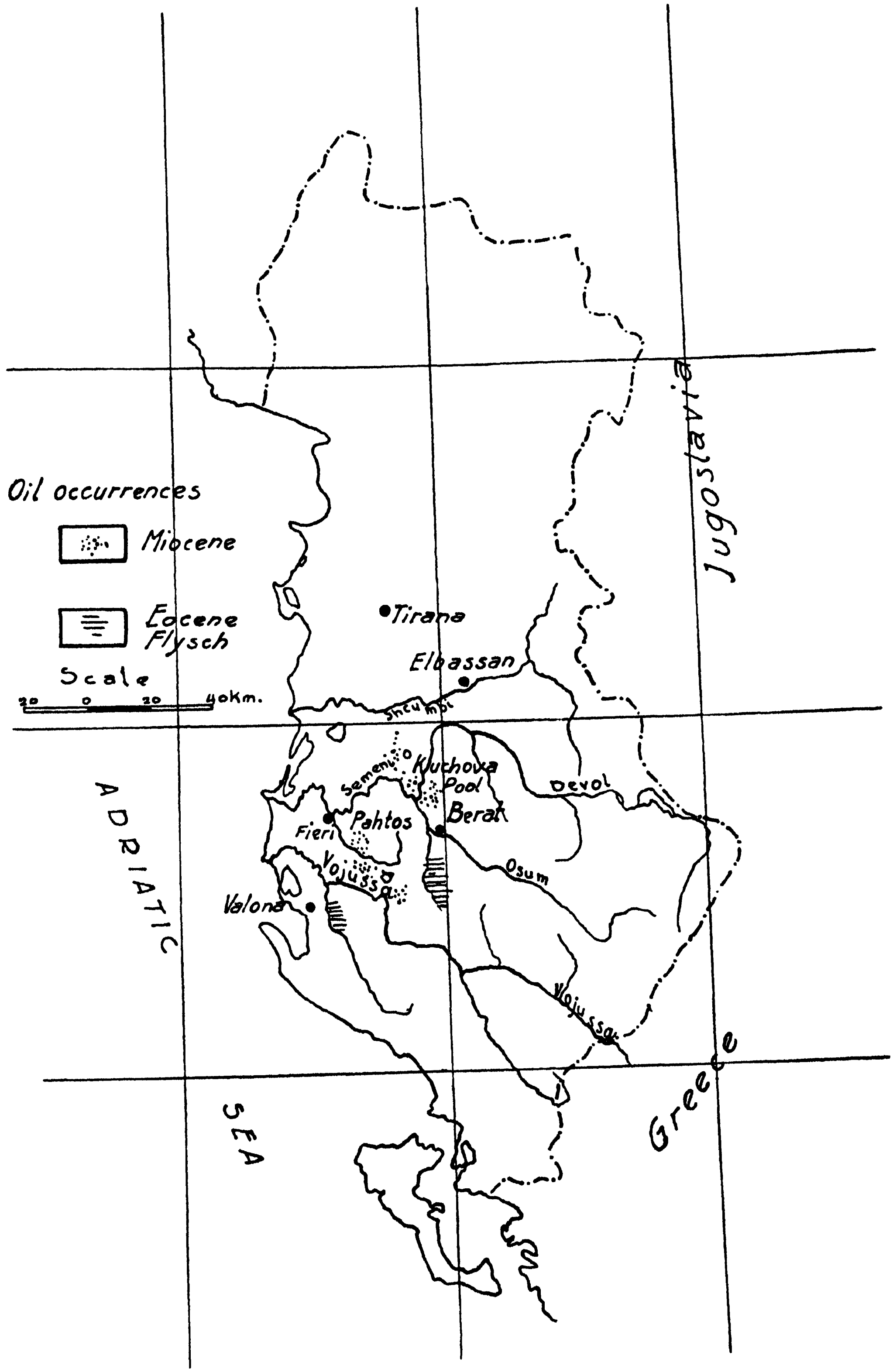

FIG. 1. Sketch-map of the main oil-shows of Albania.

and Flysch). Diffused and isolated shows of no commercial value.

Middle Eocene (Flysch). Frequent traces, sometimes even with commercial possibilities.

Basement Limestones: Lower Eocene—Mesozoic. Isolated asphaltic impregnations in the Eocene limestones. Asphalt and asphaltites are frequent in the Middle Triassic of S. Albania (Nowack [4, 1930]).

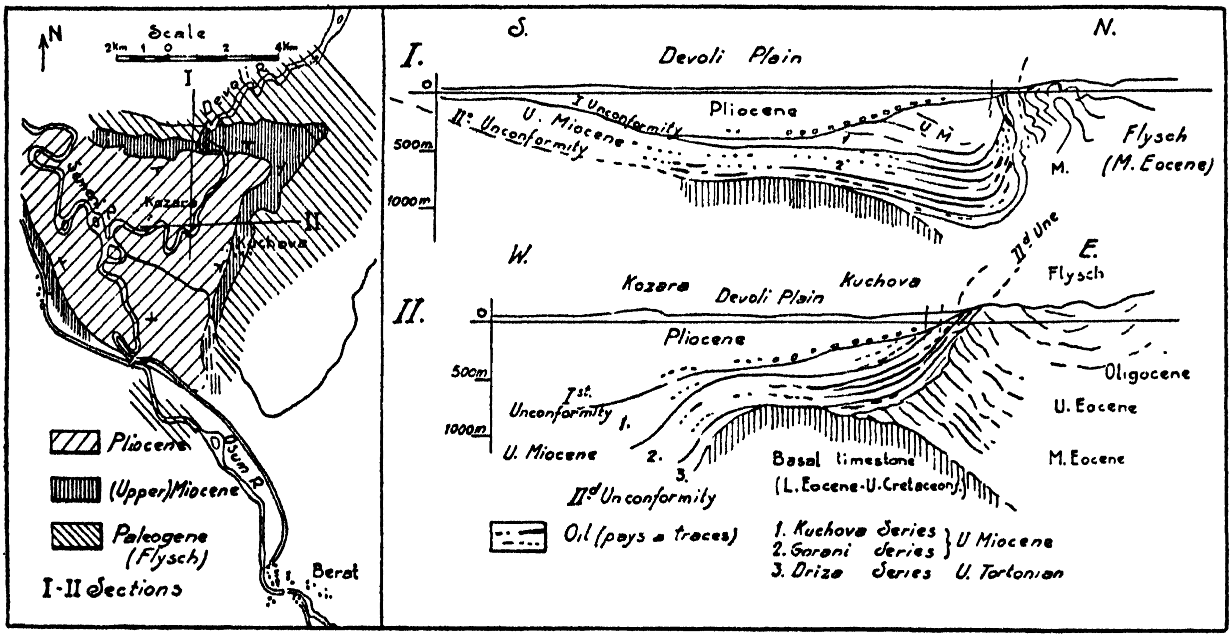

FIG. 2. Sketch-map and sections across the Kuchova oil-pool.

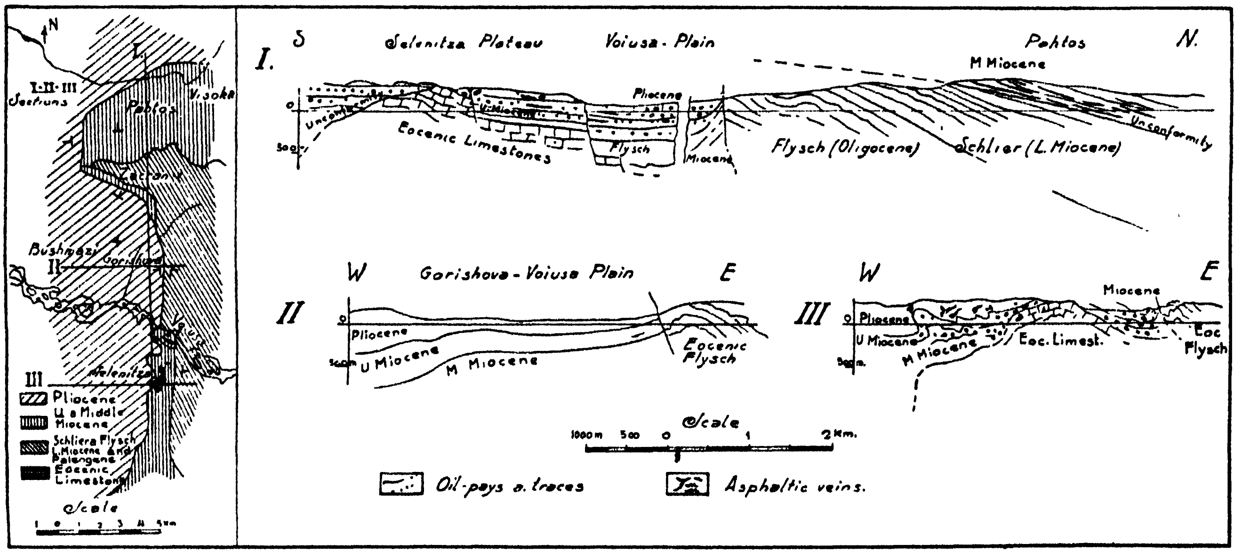

FIG. 3. Sketch-map and sections across the Pathos-Selenitza oil-bearing belt.

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CZECHOSLOVAKIA

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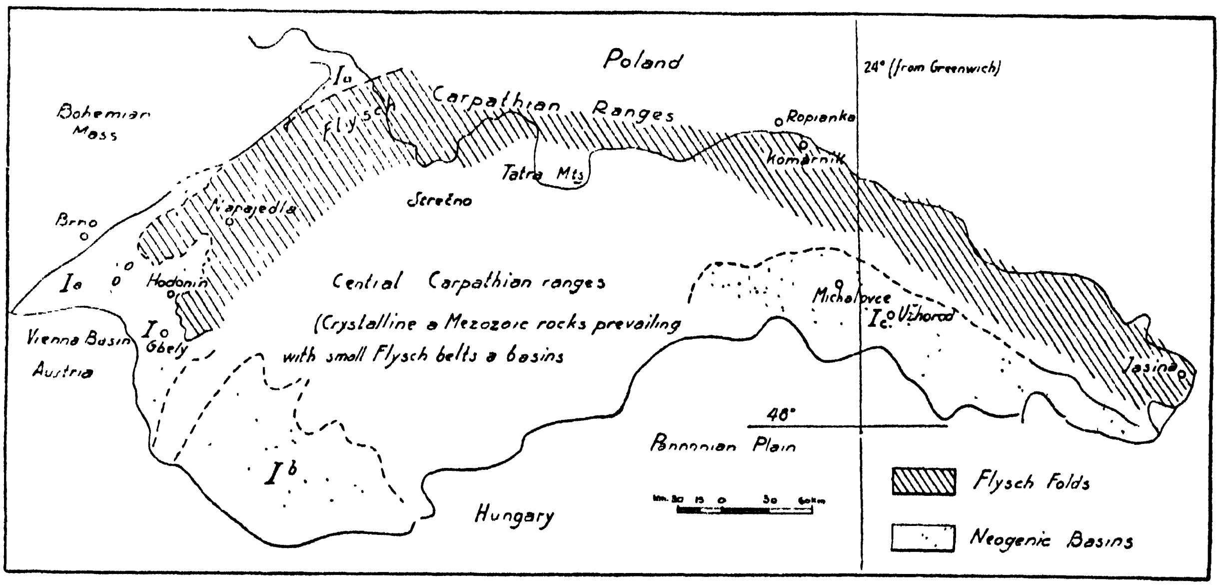
THE oil-shows of this country are located along the Carpathian arch. The two main types correspond exactly to the two different types of sedimentation and, consequently, of tectonics (see Sketch-map). The first belongs to the Carpathian flysch belt, Palaeogene and Cretaceous, composed of a bunch of folds thrust towards the north-west, north, and north-east, and having their main development in Poland with structures designated by Polish geologists as characteristically 'skiba'. The second consists of embayment basins filled up with undulating Neogene deposits, faulted and frequently broken down. These basins mark the edges of great depressions existing between the Alpine Systems, the Carpathians, and the Bohemian Mass, and which penetrate into the Czechoslovakian territory from the Vienna Basin and the Pannonian Plain.



Sketch-map of the main geological units of Eastern Czechoslovakia.

1. **The Carpathian Oil-bearing Units** represent narrow folds, frequently steep, which run parallel to the main axial direction of the chain. Their oil occurrences are connected with the Lower Eocene and Upper Cretaceous Flysch (shales and clays). Oil-shows are frequent and widespread, though production is small, due to the lack of well-developed porous formations. Escape of the oil from the beds is also restricted by the presence of secondary folding in the shales. As in the boundary oilfields of the Polish Carpathians, the search has always been hindered financially and therefore several folds, which are undoubtedly oil-bearing, have not yet been explored. Descriptions by Sommermeier [5, 1930], Zapletal [8, 1935], Matejka and Zelenka [3, 1932], and Hynie [1, 1925] distinguish these two main belts; the western to the south of the Tatra Mountains (western Slovakia and Moravia) and the eastern from the Dukla Pass (Fig. 1) to the Roumanian frontier (eastern Slovakia and the Carpatho-Russia).

The total production of the oil from the western belt has not exceeded more than a few hundred tons of light benzinous oil (average sp. gr. about 0·810).

The somewhat more favourable underground conditions of the eastern belt correspond with the gradual increase in oil saturation of the zone of Central Nappe of the Flysch Carpathians, along the Polish side of the range. At Komàrnik the total production has exceeded 10,000 tons (sp. gr. 0·805). To the east traces only have been found with a few hundred tons of production.

As on the Polish side, i.e. in the area of the Central Nappe of Flysch, all the oil deposits and traces belong to the common Carpathian type with anticlinal distribution of oil and of the edge-waters.

2. **The Moravian Neogene Embayment.** Beyond the partly unconformable Pontic-Meotic overlap, which is undulating and fractured, there is an almost complete Miocene sequence below the Sarmatian. Productive oil impregnations appear through all the Vienna Basin, of which the Moravian embayment represents a sector. Two main pools are recognized: **Gbely** and **Hodonin** (Sommermeier [5, 1930], Vetters [6–7, 1935]). Oil of 0·910–0·945 sp. gr. is found in three sands, somewhat lighter in the two upper levels, and heavier in the lower. The irregularly shaped oil-bearing sectors do not follow the tectonic structures and are distributed haphazardly. Gas blow-outs are frequently associated with the oil lenses. Water also appears irregularly. The average depths of the Sarmatian levels within the fields are 100–500 metres. The oil occurrences of the Moravian Embayment correspond to the Mediterranean type of underground conditions, which must be taken into consideration in prospecting. The successful wells in both the above fields give initial productions up to 20 tons daily.

Below the Sarmatian the Middle and Lower Miocene

are followed by the Palaeogene. The latter forms an uplifted belt which partly divides the Gbely sector from that of Brno (Fig. 1). The Tertiary shows a nearly complete sequence with only very slight unconformities. Promising oil-shows have been found in these basement rocks (Vetters [6–7, 1935], Schnabel [4, 1931]), the lithological character of which should present good conditions for the accumulation of oil, which would be controlled more by lenticularity than by structure. Similar conditions are probably associated with the promontories of the Bohemian Mass, in which region the Tertiary blocks become gradually uplifted.

3. **The Pannonian Neogene Embayment.** So far only slight traces, bounded by the Mesozoic chains of the Central Carpathians or by the Quaternary volcanoes on the edge of the Flysch Carpathians, are known. These depressions present stratigraphic conditions similar to those of the Moravian Embayment.

4. Asphaltic rocks of the Middle Triassic Dolomites of the Central Carpathian chains are known in the vicinity of **Strečno** in Slovakia. These impregnations are associated with a series that frequently shows a diffused bituminosity and probably correspond to large accumulations of heavy oil, destroyed by the thrust movements.

The yearly production of Czechoslovakia averages 15,000 tons, mostly from the Sarmatian pools. The stratigraphical distribution of oil-shows in Czechoslovakia is as follows:

Lower Pontic and Meotic. Oil and gas traces in the Moravian Embayment.

Upper Miocene (Sarmatian). Main productive sands in the Moravian Embayment.

Middle Miocene–Palaeogene. Frequent traces in the Moravian Embayment.

Lower Eocene–Upper Cretaceous. Flysch oil-shows in the Carpathians.

Triassic. An isolated exploitable asphalt occurrence in the Central Carpathians.

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POLAND

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THE whole of the Polish production comes from fields located along the Carpathian mountain front. The presence of petroleum is indicated by numerous seepages which have been used for centuries by the local inhabitants as a supply of lubricant and as a medicament for domestic animals. The first regular exploitation of these seepages appears to have commenced at the beginning of the nineteenth century, there being a record of the sale of oil from shallow pits at Boryslaw in 1816 to the Magistrate of Prague. The oil was to be used for street lighting. In 1853 the distillation of kerosine from the crude oil was commenced, drilling instead of shaft-sinking began in 1862, and in 1882 the Canadian system of drilling was introduced. With the introduction and gradual improvement of the Canadian system, deep drilling became possible and the production increased rapidly. From the year 1862 there was also a rapid rise in the production of ozokerite, and until the end of the century it remained the principal product at Boryslaw.

Shows of oil have also been reported from time to time in West Poland, especially from a zone which stretches from Tuchola (south-west of Danzig) to Kielce, but apart from a few shallow wells no developments have taken place there. The northern part of this area forms the eastern extension of the North German oil province, and the most interesting occurrence in it is the salt-stock at Inowroclaw (Hohensalza) in the province of Posen. Not only does this indicate the presence of salt structures, but the salt itself is bituminous. Very detailed prospecting work, geological, geophysical, and drilling, would be needed, however, before the possibilities of the area could be rightly judged.

Summary of the Geology of the Polish Carpathians

The Carpathians are part of the great Tertiary mountain system, and their general structure is similar to that in other parts of this system, overfolds and great thrust sheets dominating the picture. Their frontal portion in Poland is composed of Flysch sediments, and the oilfields are concentrated in this zone. Taken as a whole, these sediments are thrust over a Miocene foreland. When considered in more detail, however, it is found that they are themselves subdivided into a complex series of overthrusts and nappes which have developed from overturned and recumbent folds. It is now generally recognized that these structures fall into three major groups or nappes which, following Nowak's [3, 1929] terminology, are called Magura, Central, and East Marginal. Their present surface extent is shown on the accompanying map, and it will be seen that the Central nappe is exposed over by far the greatest area. Nearly all the western and many of the eastern oilfields fall within its limits, but the most productive of the Galician fields are found in the East Marginal nappe.

The general relationship of the above-mentioned structural elements in the Flysch zone is as follows. The Magura nappe is thrust over the Central nappe; this is, in turn, thrust over the East Marginal nappe; and finally the East Marginal nappe is thrust over the Miocene foreland.

Magura Nappe. The Magura nappe does not extend west of the meridian of Sanok. Its northern edge extended originally at least 30 kilometres north of its present position. The general structure may be described as a great overfold nappe which is divided into numerous blocks, thrust outwards over one another like, to use Nowak's simile, the tiles on the roof of a house. There are a few small fields on its outer margin to the east, and these obtain their production from strata in the Magura nappe as well as from the underlying Central nappe. In addition it is to be noted that many of the fields at present located entirely within the western part of the Central nappe were once covered by the Magura nappe.

Central Nappe. The general character of this great unit varies with its length and its breadth. Along its north-east margin there is a zone of folds and frontal overthrusts. Towards the centre this gives place to the central depression, a synclinorial zone from which, in the Sanok area, a number of folds arise and develop into overthrusts as they are traced westwards. Analogous conditions are to be found in the extreme east of the zone. The central part of the synclinorial zone is relatively little compressed, and the greatest accumulation of petroleum in the west Carpathians is to be found in this area.

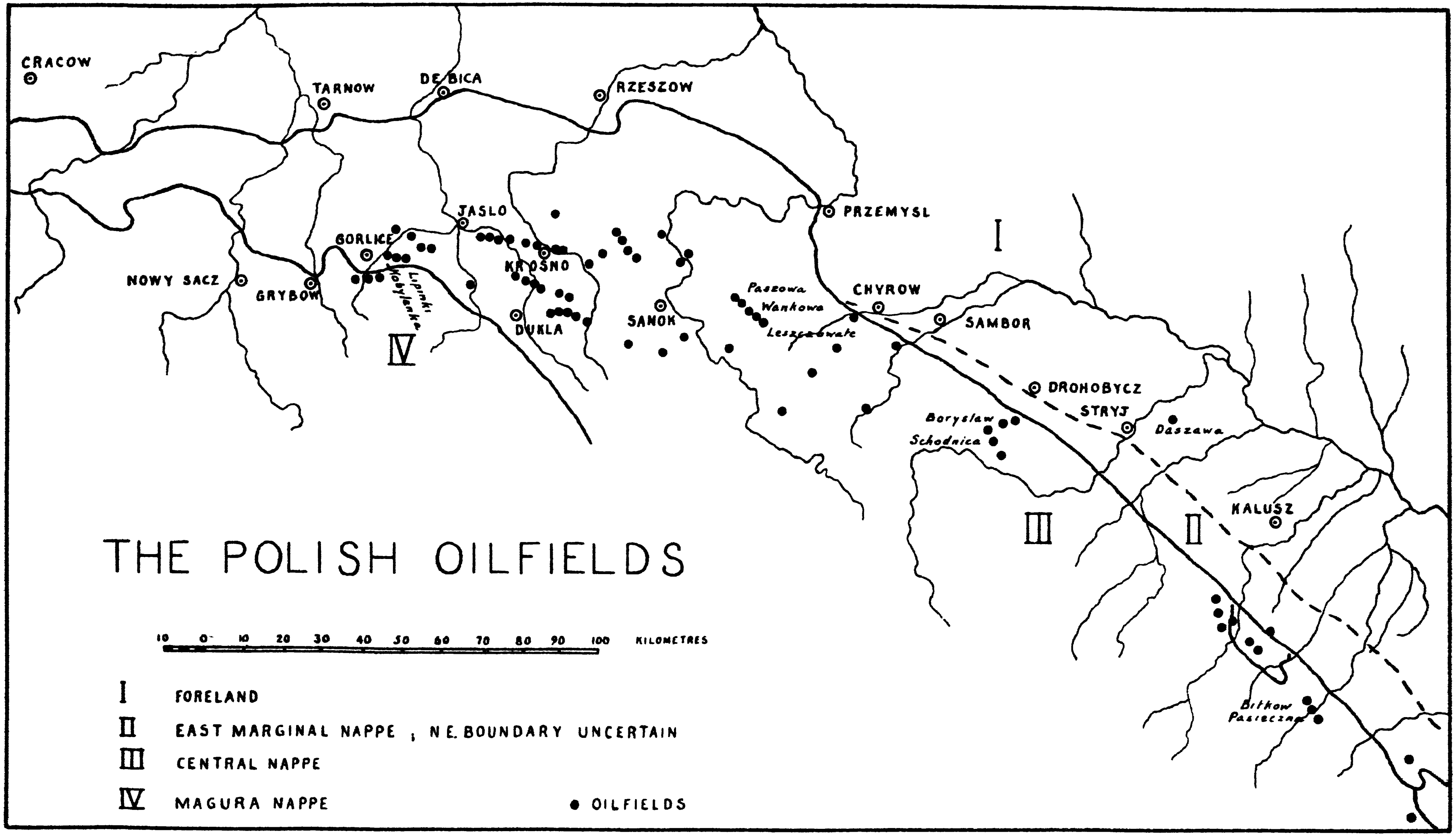
East Marginal Nappe. This is almost entirely masked by the Central nappe and, in spite of its being by far the most productive region and hence penetrated by many wells, the details of its structure are not wholly clear. This is especially the case in its relationship to the foreland, of which very little is as yet known on account of the thick cover of gravels and alluvium. The question of the subdivision of the East Marginal nappe is a matter of debate. Some workers divide it into a series of sub-nappes, Pokucie, Sloboda, and Boryslaw, whilst others see in these structures a series of connected folds. For the present the subject is best left open until further work, which is being actively pursued in the area, throws new light on the problem.

Stratigraphy

The Carpathian Flysch includes strata of Cretaceous and Lower Tertiary age. It is in general an alternating series of sandstones and shales with irregular intercalations of hornstones and calcareous marls, the total thickness being some 7,000 ft. Nowak [3, 1929] has pointed out that normally these beds become more sandy as they are traced southwards. This is a natural result of the conditions of deposition, the Flysch being a relatively shallow water, shoreline deposit originating in seas of varying depth. The detritus was supplied by the land mass to the south and probably also by chains of islands emerging along zones of uplift in the shallow sea.

Cretaceous. Although the Lower Cretaceous is well developed in the extreme west of the Carpathians, it is relatively unimportant within the zone of the Galician oilfields. It is there represented by the Wernsdorf beds or Spas shales, which are Barremian-Aptian in age and are mainly black shales.

The Upper Cretaceous is of considerably more importance in the oilfield region. Over the greater part of the


THE POLISH OILFIELDS
CRACOW
TARNOW
DEBICA
RZESZOW
PRZEMYSL
JASLO
GORLICE
KROSNO
NOWY SACZ
GRYBOW
Lipinki
Kobylanka
DUKLA
SANOK
Paszowa
Wankowa
Leszczowate
CHYROW
SAMBOR
DROHOBYCZ
STRYJ
Boryslaw
Schodnica
Daszawa
KALUSZ
Bitkow
Pasieczna
I
II
III
IV
10 0 10 20 30 40 50 60 70 80 90 100 KILOMETRES
I FORELAND
II EAST MARGINAL NAPPE ; N.E. BOUNDARY UNCERTAIN
III CENTRAL NAPPE
IV MAGURA NAPPE
● OILFIELDS

MAP I.

area it is represented by the Inoceramus formation, a series of grey clays and sandstones with local intercalations of Fucoid marls. In the extreme east a series of red and green shales and calcareous sandstones—the so-called 'Plattige' beds—forms the higher part of the Upper Cretaceous. Finally, in the marginal area in the east there is the Jamna sandstone. This is a massive, coarse-grained sandstone of Palaeocene age and some 130–300 ft. in thickness.

There is a change in facies of the Upper Cretaceous in the region west of Sanok. This change from east to west is gradual, and the typical western development is the Istebna shale series of black shales and sandstones.

Locally, the Jamna sandstone and the sandy horizons in the Inoceramus beds are oil-bearing.

Eocene. The change in facies from east to west which was noted in the Upper Cretaceous persists into the Eocene. The exact details of the Eocene stratigraphy, however, are not entirely clear. It has been usual to make a threefold subdivision, but, according to Nowak [3, 1929], recent work on nummulitic faunas shows that the two lower divisions are Lower Eocene and the other Upper Eocene. The use of the term 'Hieroglyphic' is also somewhat misleading. Some writers apply it to the whole of the Eocene, others state that it is overlain by the Popiele beds in the eastern area, and yet others confine it to the Upper Eocene and consider the Popiele beds to be a special development in the east.

The lowest strata are coloured shales with interbedded sandstones. These are followed by a more sandy series in which are the Ciezkowice sandstone in the west, and the Wygoda and Pasieczna sandstones in the east. These two series form the Lower and Middle Eocene according to the system in which a threefold subdivision is recognized. The Upper Eocene is characterized principally by the Hieroglyphic beds which are dark, greenish-grey shales with interbedded quartzitic sandstones, on the bedding planes of which the Hieroglyphics are seen. In the East Marginal nappe and also the outer part of the eastern section of the Central nappe the Popiele beds occur at the top of the Eocene. They are mainly sandy and calcareous shales.

The Ciezkowice sandstone is an important reservoir rock in the west Carpathians, whilst some oil is produced from the Popiele beds and the Lower Eocene in the east.

Oligocene. In the Central and East Marginal nappes the Lower Oligocene is characterized by the Menelite shales which are black, thinly bedded, bituminous shales with a bitumen content of 1–8%. Fish remains are abundant, especially scales of *Meletta cranata*. Sandstone intercalations are also common, and one of these, at the base of the Menelite shales, is the Boryslaw sandstone, the principal producing horizon in the Boryslaw field. The exact age of the Menelite shales is doubtful. Although they have generally been considered as Lower Oligocene, there is evidence which would seem to point to them being, at least in part, of Upper Eocene age.

The Menelite shales are normally overlain in the east by the Polanica beds, light-grey, sandy shales. In the central part of the area, however, the Krosno beds are the typical Upper Oligocene development. They are of a more sandy type than the Polanica beds and include an appreciable proportion of sandstone horizons. In the eastern part of the East Marginal nappe the sequence is somewhat different. The Menelite shales are there overlain by the Sloboda conglomerates, and these in turn are overlain by the Dobrotow beds which are sandy marls of Upper Oligocene and possibly even Lower Miocene age.

There is an important change in facies towards the west. The Menelite shales gradually give place to massive sandstone, the Magura sandstone, and this is typical in the Magura nappe for the whole of the Oligocene.

Deposition in the Magura and Central nappes ceased with the Oligocene. It continued into the Miocene in the East Marginal nappe. The important producing horizons in the eastern fields are Oligocene.

Miocene. The Dobrotow beds which cover the Sloboda conglomerate possibly extend into the Lower Miocene. They are followed in the East Marginal nappe by a red series of shales and sandstones which is in turn followed by the Salt series. This latter series consists of light-grey, saliferous, and gypsiferous clays. With the exception of a zone in the south-east, deposition ceased with the Salt series. In this zone, which is the 'Sloboda sub-nappe' of

Stratigraphical Table in the Polish Flysch Zone. (After Nowak)

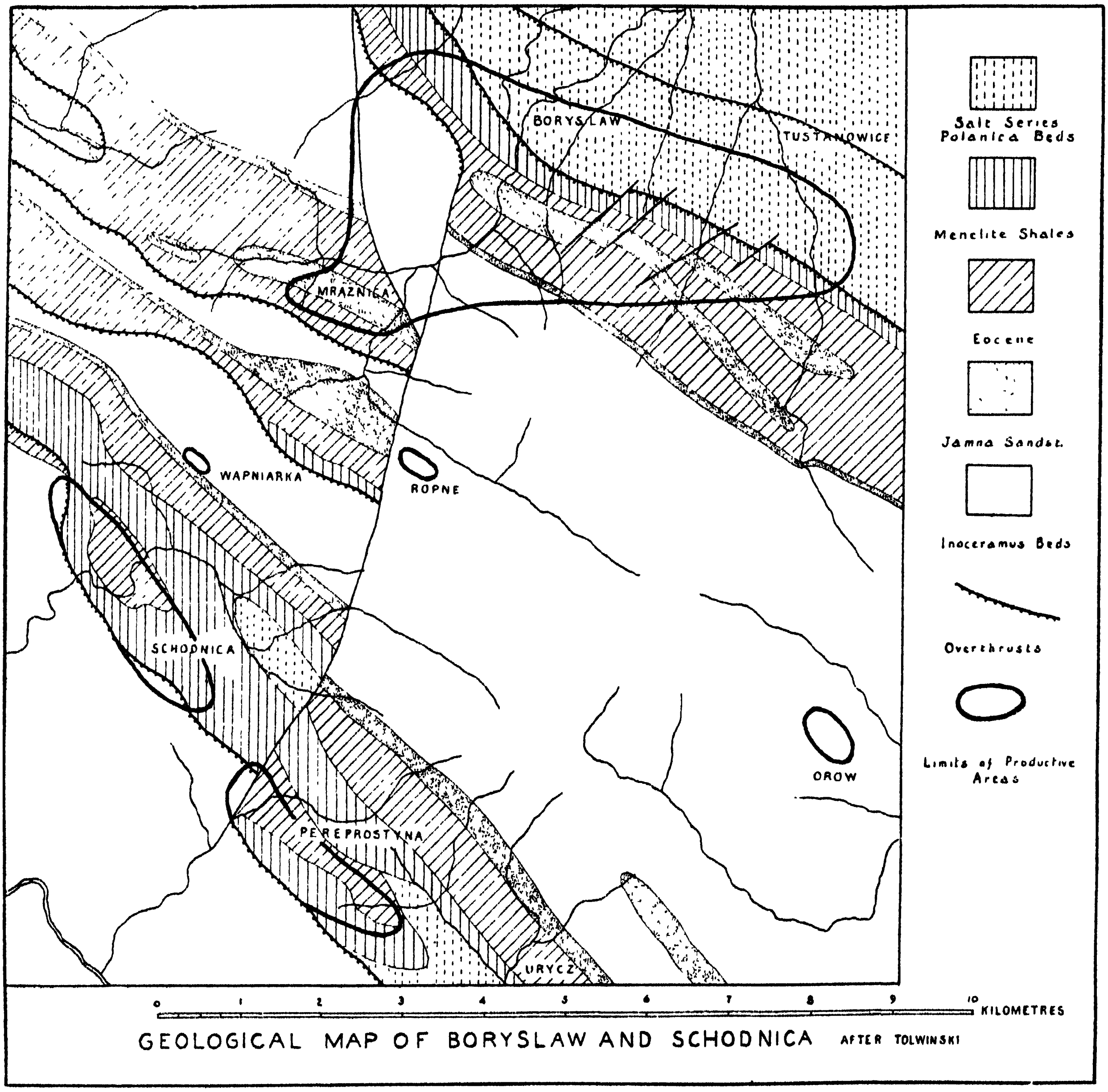
		Magura Nappe		Central Nappe		East Marginal Nappe
		W.	E.	W.	E.	
Miocene				Marine sandstone. Brackish-water clay. Lignite beds.	Dobromil conglomerates?	Tortonian Cerithium beds. Red marl. Salt clay, conglomerate, red shale, and sandstone.
Oligocene		Magura sandstone		Marly shales, Krosno sandstone.	Marly shales and Dobrotow sandstone. Dark shales and Polanica sandstone. Sloboda conglomerate.	
				Menelite shales with hornstone and Boryslaw sandstone.		
Eocene	Up.	Hieroglyphic sandstone and greenish-grey shales.		Hieroglyphic sandstone, green shales.	Popiele beds: greenish-grey, sandy shales.	
	Lr.		Ciezkowice sandstone and conglomerate, with coloured shales.		Pasieczna and Wygoda sandstones. Siliceous sandstones and coloured shales.	
		Coloured shales and sandstone.				
Cretaceous	Up.	Istebna beds: black shales and sandstone.		Black shales and Czarnorzeki sandstone.	Jamna sandstone. Calcareous sandstone, shales, and marls with Fucoids.	'Plattige' beds: red and green shales and sandstones.
					(Inoceramus formation)	
	Lr.			Wernsdorfer beds; Spas shales.		

some authors, the Salt series is covered by clays, sands, and marls of Tortonian age. The great overthrusts were developed during the Tortonian.

Miocene strata are characteristic of the foreland. The known sequence begins with a series of saliferous clays with salt and potash deposits, but it is not at all certain whether these are the same as the Salt series in the East Marginal nappe. Above this series are marls, clays, and sands, and then come the Lower and Upper Cerithium beds. The Lower Cerithium beds also contain salt deposits. The exact ages of these series are difficult to determine. They may extend to the Lower Sarmation, but in any case the productive Pliocene of Roumania is definitely absent (Friedl [2, 1930]).

The Polish Oilfields

There has been a more or less continuous decline in the Polish production from the year 1909, when Poland ranked third amongst the producing countries with an annual production of some 2,000,000 tons. In 1935 Poland was fifteenth with an annual production of about 500,000 tons. The Boryslaw field provides about 70% of the total production, Schodnica about 10%, and the remaining 20% is divided amongst forty or more other fields of which five have annual productions of 15,000–25,000 tons. The greater number of the remaining fields are therefore seen to be very small producers. In the following account only some of the more important fields can be described. Full descriptions of all the fields are to be found in papers by Friedl [2, 1930] and Nowak [3, 1929], and descriptive notes on the fields in the 'World Oil Survey Number' of the *Oil Weekly* [4, 1933].



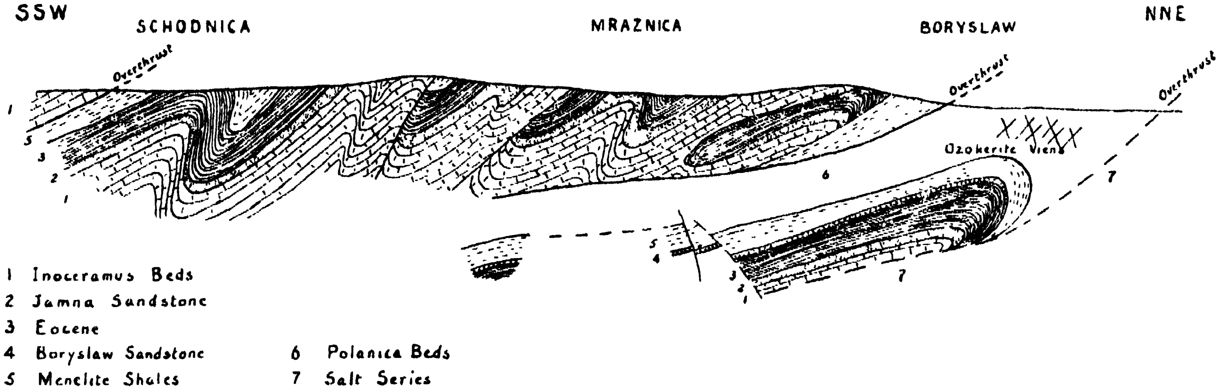
MAP II.

Boryslaw–Tustanowice–Mraznica

The Boryslaw field is located on the margin of the Central nappe, the northern boundary passing through the productive area. In the underlying East Marginal nappe there is a great recumbent fold, the Boryslaw 'deep

fold'. The subsurface of this fold is a matter of controversy. It is not known whether it rests on autochthonous Miocene strata or whether there is another thrust block beneath it. The extent of the movement of these nappes is also unknown, but it is at least several kilometres.

The field extends over an area in which there is subsidary elevation or doming on the main deep fold. It is limited on the north and north-east by the overturn, and on the west by a fault of considerable magnitude, the Ratoczyn fault. Beyond this fault only water is found. Edge-water is found in the south-east and south-west. The dip of the fold in these directions is comparatively gentle and it is broken by minor faults only. The main extension of the field is now in south-west Mraznica.



Cross-section I. From Boryslaw to Schodnica. (*After Friedl.*)

Stratigraphy. The Salt series and Polanica beds have a thickness of 750 m., but in some cases it is reduced. They pass downwards into 200 m. of black, bituminous Menelite shales which contain interbedded sandstones. Below these are the Popiele beds with a regular sandstone zone 50–75 m. from the top. The Lower Eocene is in the form of green shales alternating with quartzitic sandstones. The thickness of the Eocene varies, it being about 400 m. in the major part of the field, and of this some 120 m. are Popiele beds. Below the Eocene there lies the Jamna sandstone, 80 m. thick, and then a reduced thickness of Inoceramus beds.

Producing Horizons. Salt series and Upper Polanica beds: Sand lenses are locally somewhat productive in the crest of the fold.

Lower Polanica beds: The first important producing horizon is found in a sandstone horizon 200 m. above the base of the Polanica beds. Production is limited to the crestal area of the fold.

Upper Menelite shale: Irregular and poor production in a hornstone at the top of the series.

Lower Menelite shale: Good gas production and a little oil in sandstone zones.

Boryslaw sandstone: A series of sandstones, some 20 m. thick, of varying grade and porosity. It occurs at the base of the Menelite shale at depths of 700–800 m. in the crestal part of the fold, and at a depth of 2,000 m. at the south-west boundary of the productive zone. This sandstone series is the richest horizon at Boryslaw and has given one-half of the total production there.

Popiele beds: Good production is obtained from the sandstone horizon 50–75 m. from the top of the series.

Lower Eocene: Productive horizons are found at various parts, but their extent is very limited.

Jamna sandstone: The second best producing horizon at Boryslaw. The upper surface is at depths of 1,400 m. in the crestal zone of the fold.

The greater part of the production is obtained from the deep fold, but small quantities of oil are also obtained from the overlying Central nappe. Most of the Boryslaw oil is fairly heavy, sp. gr. 0·85, with a gasoline content of 10–15% and a wax content of 7–9%. The oil from above the overthrust has a higher gasoline content, 12–28%.

In addition to the oil mention must also be made of the ozokerite deposits for which Boryslaw is famous. The ozokerite occurs in a system of steeply dipping veins in the Salt series and Polanica beds in the crestal region of the deep fold. The strike of the veins is oblique to the trend of the fold, and the greater number strike WSW.–ENE., dipping in a northerly direction. A smaller number of generally wider veins strikes WNW.–ESE. The width of the veins varies from a few millimetres to several metres, and they are filled with a breccia composed of fragments of neighbouring rocks. The ozokerite fills the interstices in this breccia. The hardness of the wax varies with its depth from the surface, and at depth it is so soft that it has flowed into a shaft and risen to the surface.

Schodnica

The Schodnica field is located on a comparatively broad and flat fold in the zone of folds and frontal overthrusts along the north-east margin of the Central nappe. It lies immediately in front of the Skole overthrust. Two domes are developed on this fold. The more northerly of these is the Schodnica dome, and from this the fold plunges, with minor breaks, gently to the south-east until it is cut by the Ratocyn fault. The effect of this fault is to lift the fold again some 300 m., and then, immediately to the east, the second dome (Pereprostyna-Urycz) is developed. The fold plunges gently south-eastwards again from this dome.

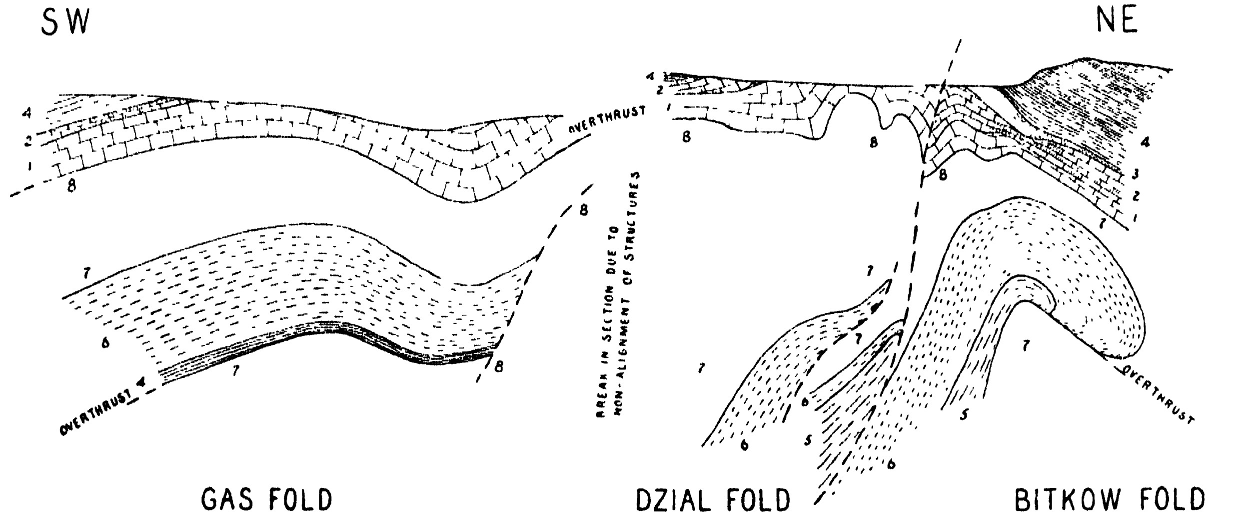
The stratigraphy is, in general, the same as at Boryslaw, with the exception that the Salt series is absent and the Polanica beds are greatly reduced in thickness. The principal producing horizon is the Jamna sandstone which is about 70 m. thick. The productive area is limited by edge-water to the two domes. The Inoceramus beds below the Jamna sandstone are also productive and offer now the best possibilities for expansion. A small amount of oil is obtained from irregular sand lenses in the Lower Eocene, but the Upper Eocene and the Menelite shales outcrop and are not productive.

Bitkow–Pasieczna

The Bitkow field lies more than 100 km. to the south-east

of Boryslaw and is situated 6 km. within the edge of the Central nappe. The producing structures are developed in the underlying East Marginal nappe which can be seen at a number of small windows in the district. The Bitkow fold itself is an arched recumbent fold, the brow of which is overturned. It is part of a schuppen structure of which it forms the northern unit. The Dzial fold follows to the south and is itself divided into a number of thrust blocks, and finally there comes the Gas fold which is a much less disturbed structure.

The Salt series and the Polanica beds are more or less normally developed in the Bitkow fold, but the Eocene is considerably reduced in thickness and the Cretaceous is completely absent. The Bitkow field is the third largest producer in Poland. Production is obtained from both nappes. In the Central nappe, producing horizons are found in the 'Plattigen' beds (Upper Cretaceous) and the Jamna sandstone. The major production is obtained, however, from the Menelite shales in the East Marginal nappe and it is limited to the Bitkow and Dzial folds. The Gas fold yields only gas.



1 Inoceramus Beds 2 Plattige Beds 3 Jamna Sandstone 4 Eocene 5 Shales, age doubtful 6 Menelite Shales 7 Polanica Beds 8 Salt Series

Cross-section II. Through the Bitkow field. (*After Zetechowski.*)

Paszowa–Wankowa–Leszczowate

As an example of the west Carpathian fields Paszowa–Wankowa–Leszczowate may be cited. This field has an annual production of more than 20,000 tons. It is located on a long anticlinal structure which plunges to the west and to the east, and which is overturned to the south-west, instead of the north-east as is usual in this region. The production is mainly from the Krosno beds under the south-west limb. In the south-east part of the field, at Leszczowate, a second producing horizon has been found in the Menelite shales at depths of 700 m., also on the south-west flank.

Dominikowice–Kobylanka–Lipinki Libusza

This field is situated immediately to the east of the town of Gorlice and is one of those fields once covered by the Magura nappe. The structure is anticlinal. It strikes north-east from Lipinki to Libusza with an overturn to the north-west. To the west of Libusza the anticline appears to fork in the Kryg–Kobylanka–Dominikowice area. The southern part is a broad, domed structure, whilst the northern part is a narrow isoclinal fold. Production is from the Ciezkowice sandstone.

Daszawa

Although no oilfields have been discovered in the foreland zone, a gasfield has been developed at Daszawa, 10 km. east of the town of Stryj. The productive horizons are at depths of 700–800 m. and are fine-grained sandstones separated by soft shales of Upper Miocene age. The dip of the beds is gentle, but little is published concerning the structure.

Origin of the Oil

There are two main theories concerning the origin of the Polish oil. The first postulates formation in the sub-Carpathian Salt series, and the second assumes that the mother rock occurs in the Flysch sediments. From a general consideration of the characteristics of the various oils and their occurrence Friedl [2, 1930] favours the first viewpoint and believes that the oil has migrated from the Salt series up into the Flysch which has been thrust for great distances over it. As opposed to this theory, however, Cizancourt [1, 1931] points out that no oil deposits are known in the foreland zone with its great extent of saliferous strata.

Amongst those favouring a Flysch origin for the oil, some limit the mother rock to the bituminous Menelite shales, whilst others consider that suitable mother rocks occur throughout the Flysch. Nowak [3, 1929] has sought to trace a connexion between the petroliferous areas and facies, and states that in these areas deposition was in episynclinal zones.

These different viewpoints have been summarized by Cizancourt [1, 1931], who concludes that the oil was formed in the Flysch during a period of rapid and intermittent sedimentation in not very deep seas. Synclinal zones adjacent to uplifted areas were probably the most favourable regions for its formation and, according to local conditions, all or part of the series may have contributed. Accumulation took place during the Early Tertiary folding, and the subsequent overthrusting and formation of nappes did not appreciably alter the distribution of the fields.

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GERMANY

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THE German oil occurrences are found in three quite separate areas, viz.:

(1) the Zechstein (Permian) basin in north and central Germany;
(2) the Rhine graben;
(3) the Alpine foreland zone in Bavaria.

The presence of petroleum in Germany has long been known. The seepage at Tegernsee, Bavaria, was famous in the fifteenth century on account of the alleged curative properties of the oil. In north Germany the *teerkuhlen* were a source of lubricating material for the peasants until late in the nineteenth century, when systematic development of the oil resources began. This has reached its height in post-war years, and widespread exploration, subsidized by the government, is now being conducted. The total production during 1935 was of the order of three million barrels, more than double that of 1930, and of this more than 90% came from the Zechstein basin. The Bavarian occurrences are as yet of no economic significance.

The Zechstein Basin of North and Central Germany.

The Zechstein basin began to form at the commencement of Upper Permian time and stretched from England, across north Germany with an embayment into central Germany, and on into Russia. In it were deposited the lower- and mid-Zechstein dolomitic limestones, shales, and marls. Towards the end of the Zechstein conditions changed, the sea became landlocked, and desiccation set in with the consequent formation of large deposits of salt and gypsum. These salt deposits are the characteristic feature of the basin which, as a result of later movements, can be subdivided as follows:

Northern part	North-west basin—almost complete sequence of Trias, Jurassic, Cretaceous, and Tertiary deposited on the Zechstein in central part of basin. Total thickness more than 10,000 ft. The 'Pompeckj Schwelle'—Buried ridge. Jurassic and most of Lower Cretaceous absent. Thick deposits of Upper Cretaceous and Tertiary resting unconformably on the Trias. North-east basin—Jurassic and Cretaceous present above the Trias, but in reduced thickness and incomplete sequence. Facies different from that in north-west basin.
Southern part (of this, only Thuringia is considered here).	Complete sequence of Trias. Deposition stopped very early in Jurassic. Zechstein buried to depths of only 4,000–5,000 ft.

The attitude of the salt changes as it is traced from the margin of the basin towards the interior. In the marginal zone it is interbedded normally with the strata above and below; farther inwards it shows considerable thickening in the crests of anticlines; and finally, as the centre of the basin is approached, the true salt-domes and salt stocks are developed. The reasons for these variations and the mechanics of salt-dome formation are dealt with at some length by Stille [6, 1925], Romanes [4, 1931], Harbort [2, 1913], and Seidl [5, 1913]. The oil is closely associated with these structures, and two types of occurrence may be distinguished:

(1) The marginal zones of the basin—oil occurs in the Zechstein.
(2) The interior of the basin—oil occurs in post-Zechstein strata around the salt-domes.

These two types are structurally very dissimilar and therefore will be considered separately. The general stratigraphy of the Zechstein basin is given in the Table on page 186.

The Marginal Zones of the Zechstein Basin.

The principal areas which are included under this heading are the western margin of the north-west basin, in the neighbourhood of Bentheim on the Dutch border; the southern margin of the north-west basin, north of the Harz mountains; and a large part of Thuringia. Compared with the interior of the basin, the Zechstein in these marginal zones has been affected only to a small degree by the later disturbances. In general the structures are comparatively gentle folds with irregular faulting and, as mentioned earlier, the salt retains its original form as a bedded deposit.

The most important discovery of this type yet made was in the potash mine at Volkenroda, some 10 km. north-east of Mühlhausen in Thuringia. An explosion in 1930 led to borings being made from the mine workings, and these found a prolific source of oil in the mid-Zechstein Hauptdolomit which is there some 180 ft. thick. The oil has accumulated in cracks and fissures in the dolomite on gentle, anticlinal structures. During 1931 over 50,000 metric tons were produced, but after 1932 a very rapid decline began. Other wells have been drilled in Thuringia since this discovery, notably at Mühlhausen, Langensalza, Zimmern, and Kirchenheilingen, but with little or no success.

A small production (75 bbl. per day, Sept. 1935) has been obtained from wells on the Fallstein uplift, an anticline on the north side of the Harz mountains. The Zechstein there is reached at depths of 4,000 to 5,000 ft., and production is reported to be from the 'upper' dolomite. Other wells have been drilled on well-developed anticlines in the Magdeburg-Halberstadt district, but no results of economic importance have as yet been obtained. It should be noted here that the Hauptdolomit, which is the productive horizon in Thuringia, is in this district represented by the Stinkschiefer, which are mostly bituminous and marly limestones.

Well-developed anticlinal structures are found in the Bentheim district, and the asphaltic impregnations which occur there are probably indications of petroliferous horizons. In contrast to the areas already mentioned, however, the Jurassic and Cretaceous are also present. A well drilled on the Ochtrup anticline, 10 km. south of Bentheim, is reported to have obtained heavy oil from shattered mid-Zechstein dolomite at a depth of 1,750–1,800 ft.

The Inner Part of the Zechstein Basin.

The productive areas in this zone are confined to the north-west basin, and the oil has accumulated in structures

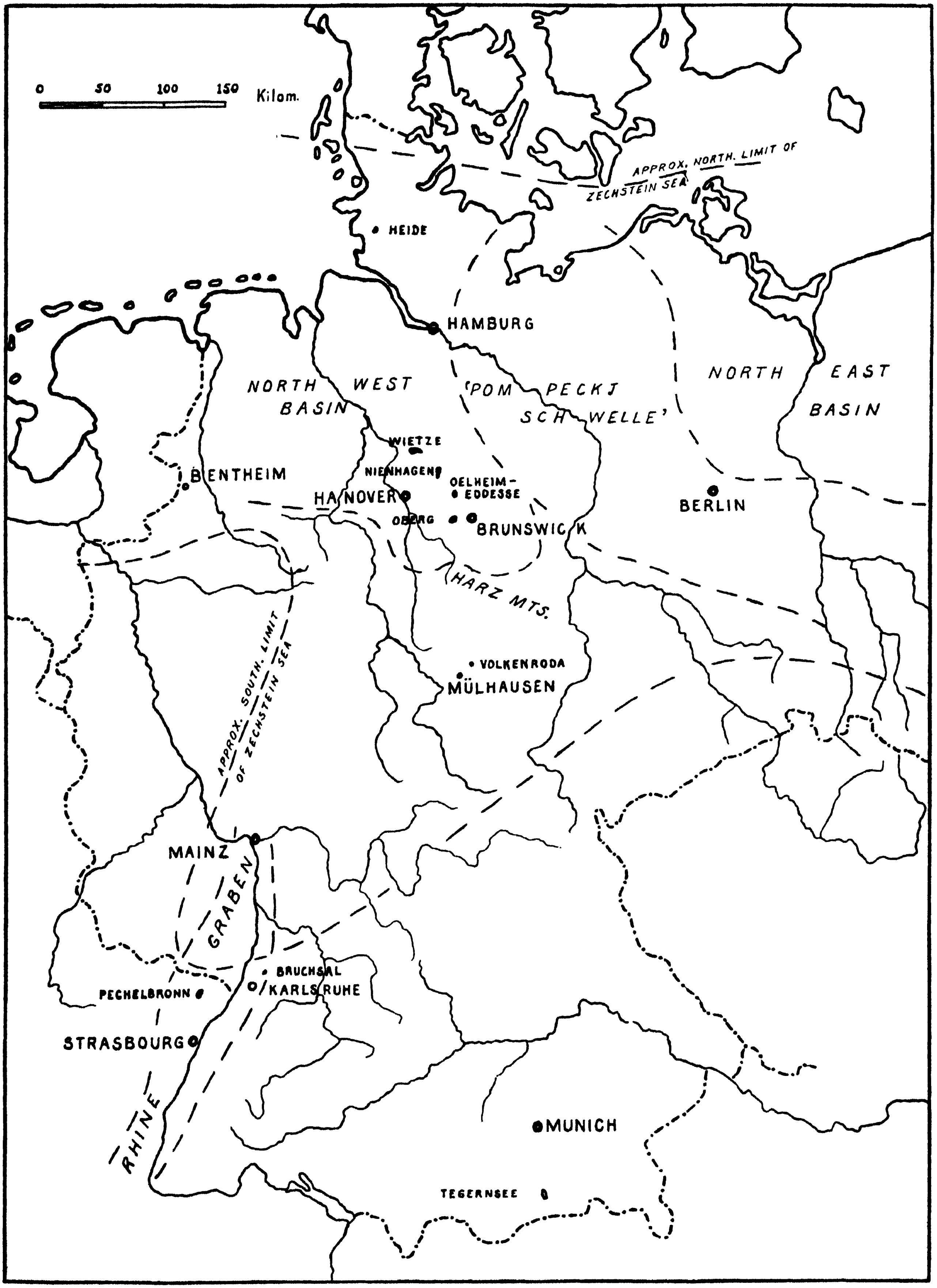

FIG. 1. Map showing the distribution and general geological features of the German oilfields.

developed in post-Zechstein strata by the uplift of the salt. The four principal fields in Germany, Wietze, Nienhagen, Oelheim-Eddesse, and Oberg, are of this type and they lie roughly on a NW.–SE. line some 30 km. to the north-east of the city of Hanover. The producing horizons range in age from Rhaetic to Lower Cretaceous, whilst small quantities of oil have been obtained from Upper Cretaceous and Tertiary horizons. When examined in detail the structures are very complex and are complicated by numerous unconformities due to late Jurassic and Cretaceous earth-movements. It is impossible to review all of these factors in the space here available, and the following account will be confined to a general, and therefore only approximate, description of the structures in the more important cases and brief mention of the others.

Nienhagen is at present the most important field in Germany. The oil is found in structures developed on the west flank of the Hänigsen–Wathlingen salt-stock which is elongated in a NNE.–SSW. direction. Early development was restricted to the seepage zone in the south where heavy oil was produced from shattered formations—mainly Triassic—at the edge of the salt. Later development spread northwards, and first a highly disturbed central zone was found to be productive, mainly from the Rhaetic and Lower Lias. Finally the north field was discovered, and this has proved to be by far the most productive. An anticline strikes WNW.–ESE. across the northern end of the salt. It is strongly folded close to the salt mass but broadens out away from the salt, and deep drilling through the Tertiary and Upper Cretaceous discovered the main oil sand in the Valendis. Oil is also obtained from the Wealden and the Upper Dogger.

General Stratigraphical Table for the Zechstein Basin, showing the Oil Horizons in the Principal Fields

Formation		*Lithology*	*Thickness, ft.*	*Wietze*	*Nienhagen*	*Oelheim-Eddesse*	*Oberg*	*Heide*	*Thuringia*
DILUVIUM		Sands, gravels, loess, peat, clay	300±						
TERTIARY		Sands, gravel, clay, lignite, limestones	3,500±						
UPPER CRETACEOUS	Senonian	Calcareous marls and sandstones, conglomeratic beds	2,500±	H	..	..	..	H*	
	Emscher	Sandy marls							
	Turonian	Marls and limestones							
	Cenomanian	Limestones and marls							
LOWER CRETACEOUS	Albian	Marly and bituminous shales with siderite nodules	2,000±	..	..	..	..	L	
	Aptian	Clays and marls							
	Barremian	Marly clay							
	Hauterivian	Marly clay							
	Valendis	Limestones and sandstones	..	..	L*				
	Wealden	Sandstones and shales	..	H*	M	H	H		
MALM	Purbeck	Shales, limestones, sandstones, gypsum	1,200±	H					
	Portland	Marl							
	Kimmeridge	Marl and oolitic limestone	..	H					
	Oxford	Shales, sandstones, and marls	..	..	..	..	L		
DOGGER	Callovian	Sandy shale and calcareous sandstone	600±	H	M	L	L		
	Bathonian	Marls, shales, sandstone							
	Bajocian	Dark shales with nodules and sandstone at base	..	..	H	L	L*		
LIAS		Shales with nodules, marls, sandstones	800±	..	H				
KEUPER	Rhaetic	Sandstones and shales	1,300−	L	H	L*			
	Gipskeuper	Marls and sandstone							
	Kohlenkeuper	Dolomite, clay, sandstone							
MUSCHELKALK		Limestone, marls, dolomite	1,000±						
BUNTER	Upper	Dolomitic limestone, marl, and calcareous sandstone	3,000±						
	Middle	Shales and massive sandstone							
	Lower	Shales, sandstone							
ZECHSTEIN	Upper	Anhydrite and Younger rocksalt	700±						
		Hauptanhydrit							
		Grey salt-clay							
		Older potash beds							
		Older rocksalt							
		Basal anhydrite							
	Middle	Stinkschiefer	..	..	..	..	..	..	L*†
		Anhydrite and rocksalt							
	Lower	Limestone							
		Kupferschiefer							
		Conglomerate							
ROTLIEGENDES		Red sandstone, conglomerates	2,500±	..	..	..	..	..	?

* = Main oil horizons. H = Heavy oil. M = Medium oil. L = Light oil.
† Stinkschiefer are here represented by the Hauptdolomit.

The Wietze field is distinguished by the fact that about one-half of the present production is obtained by mining methods. The north-west end of the Steinförde–Hambühren salt mass is anticlinal in structure, with a WNW.–

ESE. strike, the salt forming the core of the anticline, and the Trias, Jurassic, and Cretaceous forming the flanks. These are considerably broken by dip faults, and in addition there is an overthrust on the north flank. The Wietze field is limited to the north and north-west flanks, and oil is obtained from the Rhaetic below the thrust and from the Jurassic and Cretaceous above the thrust. The principal horizons are the Upper Dogger and, especially, the Wealden, whilst an appreciable production is obtained from the Senonian. With the exception of the Rhaetic oil, which is light, all the oil is heavy.

The Oberg structure is separated from the Oelsburg salt-stock by an Upper Cretaceous graben. The structure itself is a broad arch in the centre of which the Upper Dogger outcrops surrounded by crescent-shaped outcrops of Malm, Wealden, and Lower Cretaceous. The subsurface structure is complicated by a number of unconformities as a result of which various zones of the Malm begin to wedge in down dip. The main producing horizon is a sandstone in the Lower Dogger. Small production has also been obtained from the Upper Dogger and the Heersumer beds in the Malm. Some 8 km. to the south-west of Oberg there is a similar structure associated with the Moelme salt-mass. After many test borings had been made a well came in during 1935 and produced 30 tons per day from the Jurassic. Full details of this occurrence are not yet available.

In contrast to the Nienhagen, Wietze, and Oberg fields the Oelheim–Eddesse field is not associated with an obvious anticlinal structure. The strata around the Oedesse salt-stock have been lifted into steeply dipping positions by the salt and broken by radial and peripheral faults. The sequence is complete to the Upper Dogger, but the Wealden lies unconformably on this. The old Oelheim field was developed on the south-east flank where shallow production was obtained from the Wealden and the Tertiary sands. Post-war development led to the discovery of the deeper Eddesse (Berkhöpen) field where light oil is obtained from the Rhaetic at depths of 3,000 ft. Apart from these producing horizons, shows are obtained in all the strata with the exception of the Senonian.

The most northerly occurrence is at Heide in Holstein. A faulted Permian horst is covered by Upper Cretaceous beds and the chalk is in places saturated with heavy oil. Attempts to work this occurrence, both by wells and by mining, have been made at different periods, and recently drilling there has been resumed. It has been reported that a well has given a steady production of 130 bbl. per day from the 'sandy marls of the lower strata of the red sandstone' (Rotliegendes ?).

A recent development is reported from Gifhorn, 25 km. north of Brunswick. Wells have obtained production from the Wealden, which is said to be above the salt-cap, and they are yielding 50–100 bbl. per day. The true significance of this discovery cannot be appreciated until further details are published.

In addition to the above-named areas, small quantities of oil have been obtained from Horst–Wipshausen (15 km. north-west of Brunswick), Hordorf (15 km. north-east of Brunswick), Hope (25 km. north of Hanover), and Lehrte (15 km. east of Hanover), and shows from many other localities. They have, however, so far proved to be of no economic value.

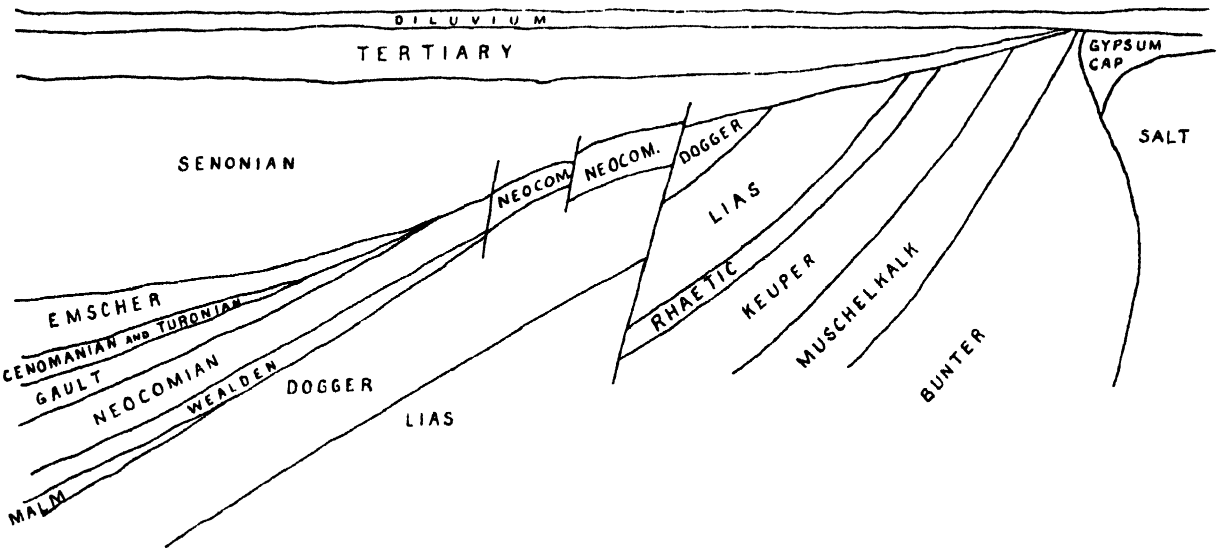

FIG. 2. Cross-section through the Nienhagen field. (*After Strobel.*)

The Origin of the Oil in the Zechstein Basin.

This highly controversial subject can be summarized briefly as follows. There is unanimous agreement that the oil found in Zechstein horizons is primary and originated there. With regard to oil found in post-Zechstein horizons there are two schools of thought. One claims it to be Zechstein oil which has migrated up fault zones at the edges of the salt-stocks; the other considers that suitable source rocks are to be found in the Mesozoic and that to postulate a Zechstein origin for this oil is unnecessary. An excellent summary of the various arguments and points of view is to be found in a publication by Stutzer [7, 1935].

The Rhine Graben.

The Rhine Graben extends from Basle to Mainz and is bounded on the west by the Vosges and the Hardt mountains, and on the east by the Schwarzwald and the Odenwald. The subsidence began in the Tertiary and was especially active during the Oligocene. Altogether there are some 4,500–6,000 ft. of Tertiary sediments, the greater

part being Oligocene in age. The region is broken into numerous fault blocks by faults more or less parallel with the main boundary dislocations. The greater part of the oil production comes from the Pechelbronn field in Alsace, a description of which has been given by Zuber elsewhere in this volume (France: S. Zuber, p. 193). Exploratory drilling at Bruchsal in north Baden during the years 1921–6 led to the discovery of another small field, similar in type to Pechelbronn. A detailed account of this work is given by Moos [3, 1935]. In general the Oligocene is not so well developed at Bruchsal as at Pechelbronn, and the sandy reservoir rocks in the Pechelbronn beds (Lower Oligocene) are missing. Production is obtained from the green marls in the dolomitic zone (Basal Oligocene) and from the upper Meletta beds (Mid-Oligocene). Wells drilled recently in this area have also given a small production from the Jurassic.

Oil and gas shows are found elsewhere within the Rhine graben in German territory, notably in the Palatinate, near the Buchelberg and Durkheim, and on the east side of the Rhine between Heidelberg and Darmstadt. Drilling in these areas is contemplated.

The Alpine Foreland Zone in Bavaria.

Tertiary sediments are found in front of the northern overthrusts of the Alps from Austria, through Bavaria and Switzerland, to France. In Bavaria these sediments are bounded on the north and north-west by the Bohemian massif, whilst in the south they are overridden by the Flysch (Cretaceous) overthrust sheets.

The Tegensee occurrence is in the overthrust zone and the structure is very complicated. The Flysch is overturned and overthrust over itself, and in addition is very much faulted. A number of wells have been drilled but only very small quantities of oil have been obtained. It is a light, paraffin base oil and it is produced from the Flysch and also from the underlying Helvetian. There is little evidence concerning the origin of the oil; it may be a Flysch oil or it may have migrated up from the Molasse (Upper Oligocene) over which the Flysch has been thrust.

In the Tertiary basin to the north of this overthrust zone the structures are more simple (Barton [1, 1934]). Wells are now being drilled near Augsburg to test the possibilities of that area.

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ITALY[1]

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NEARLY all the oil occurrences of Italy belong to the Apennines or to their foreland. Their distribution is quite irregular and no continuous oil-bearing formations can be discerned. Notwithstanding, certain deductions can be made. The main feature of the Peninsula is formed by the Apenninic system, which forms the borders of the Tyrrhenian Sea from the Maritime Alps down to Sicily. At present the opinion prevails that the range owes its structure to great thrusting movements (de Wijkersloth [10, 1934]). The overthrusting, except in the central sector, March–Abruzzo, results in a peculiar character, in which the so-called 'argille scagliose', a kind of 'wildflysch' of the Alpine geologists, is of great importance. The lack of clearly expressed tectonic features and a predominance of small, fractured rather than folded blocks chaotically mixed in a breccia of the 'argille scagliose' also gives an idea of the character of the tectonic movements. Consequently they would not be the common Alpine or Carpathian overthrusts, but earth movements of several phases, one over another, ranging in age from the Cretaceous to the Pliocene.

The oil occurrences directly connected with the 'argille scagliose' Apennines exactly reflect these conditions and certainly are the remnants of greater impregnated units which have been destroyed. In the case of the Apennine sector near Parma and Piacenza a probability exists of the presence of tectonic 'windows' partially visible through the upper tectonic 'slumps'. Notwithstanding the efforts of many geologists, no satisfactory sections across the whole range exist. Some attempts have been made by Anelli, Sacco, Fossa Mancini [5, 1933; 6, 1926; 7, 1923], and lastly by Wijkersloth [10, 1934].

The Central Apennine with its Miocene molasse without the 'scagliose' flysch (Bonarelli [2, 1930]) shows more regular conditions in so far as its structures have a rather autochthonic character. The **Apennine Foreland** consists of block-faulted undulations with a limestone basement which have been partly explored by geophysical means (Belluigi [1, 1932]) and by recent deep tests in the depressions.

The main oil-shows and the oil-pools of Italy so far recognized can be subdivided into several groups. Such subdivisions are territorial, but they coincide with the main types of oil and its occurrences (Fig. 1).

I. The Emilian Belt

The majority of shows follow the disturbed zones, being connected with impregnated rocks of Upper Eocene, Oligocene, and Lower Miocene age. They extend from Pavia and Voghera up to the surroundings of Bologna.

Velleia and Montechino. A faulted and folded block of hard marls and marly sandstones (Eocene and Oligocene) is surrounded by intrusive belts of 'scagliose' breccia. No distinct oil sands have been observed, but productive shows have been obtained with initial productions of some hectolitres daily up to a flow of 40 tons in one of the wells of Montechino. The average depths of wells are 500–800 metres. The oils are highly aromatic (55%) without asphaltic residues (sp. gr. 0·775–0·797) (Salomon-Calvi [8, 1930]). The rapid decrease of production is connected with the abundant edge-water (bromo-iodic brines).

Vallezza. A folded block of hard marls and marly sandstones (Oligocene–Eocene) surrounded by 'scagliose'. The average specific gravity of the oil is 0·810. Production and edge-water conditions are somewhat similar to those in the Montechino pool.

Salsomaggiore. A highly fractured block of sandy marls (Lower Miocene–Oligocene) situated on the edge of the hills with productive oil-shows near the top of the Oligocene (sp. gr. of this oil is 0·801–0·833). The abundant bromo-iodic brines of high salinity are utilized for medicinal purposes.

The Sub-Apennine Emilian Plain.

Podenzano. The oil-shows contain a high percentage of gas. The top of the Upper Miocene is folded and is covered by an unconformable Pliocene overlap (sp. gr. of the oil is 0·869–0·897).

Carpaneto. A small oil-show within the Pliocene beds and near to their base, which is quite an isolated occurrence.

Fontevivo. Oil is found on the top of the Upper Miocene covered by the Pliocene overlap. Gas-shows are found near the base of the Pliocene. Production is several tons daily (sp. gr. 0·847). Bromo-iodic brines of high salinity are very abundant.

The oils and brines so far discovered in the plain are very similar to those of the Emilian Apennine. Stratigraphically they seem connected only with the base of the folded Upper Miocene. Nevertheless, their position still remains somewhat enigmatic. Abundant gas-shows accompanied by strong blows have been noticed in several deep tests drilled in the Emilian Plain.

II. The Central and Southern Apennine

Oil- and Asphalt-shows in the Pescara Basin. Asphaltic oil impregnations occur in a Neogene embayment (Upper and Middle Miocene) along the promontories of the Maiella Massif. Molasse-gypsum sediments are associated with the organic deposits (Lithothamnium and Bryozoic Limestones). Near the asphaltic impregnations in the Middle Miocene fluid oil is found in small quantities (sp. gr. 0·920 and more) (Fig. 2).

Valle Latina. This is a graben-like, folded and faulted depression between calcareous massifs (Cretaceous) filled with Miocene deposits, with molasse on the top (Upper and Middle Miocene) and flysch-like sediments at the base (Lower Miocene). Viscous asphaltic oils (sp. gr. 0·95 and more) are found in the Lower Miocene and insignificant shows of lighter qualities in the Middle Miocene. A pay has been exploited at S. Giovanni Incarico (Fig. 3) yielding several tons daily from average depths of 300–450 metres.

Asphalt-shows. In the whole area of the Abruzzo Highlands large and frequent asphaltic impregnations exist, connected with the breccia limestones of the Lower Cretaceous. They can be considered as weathered oil deposits.

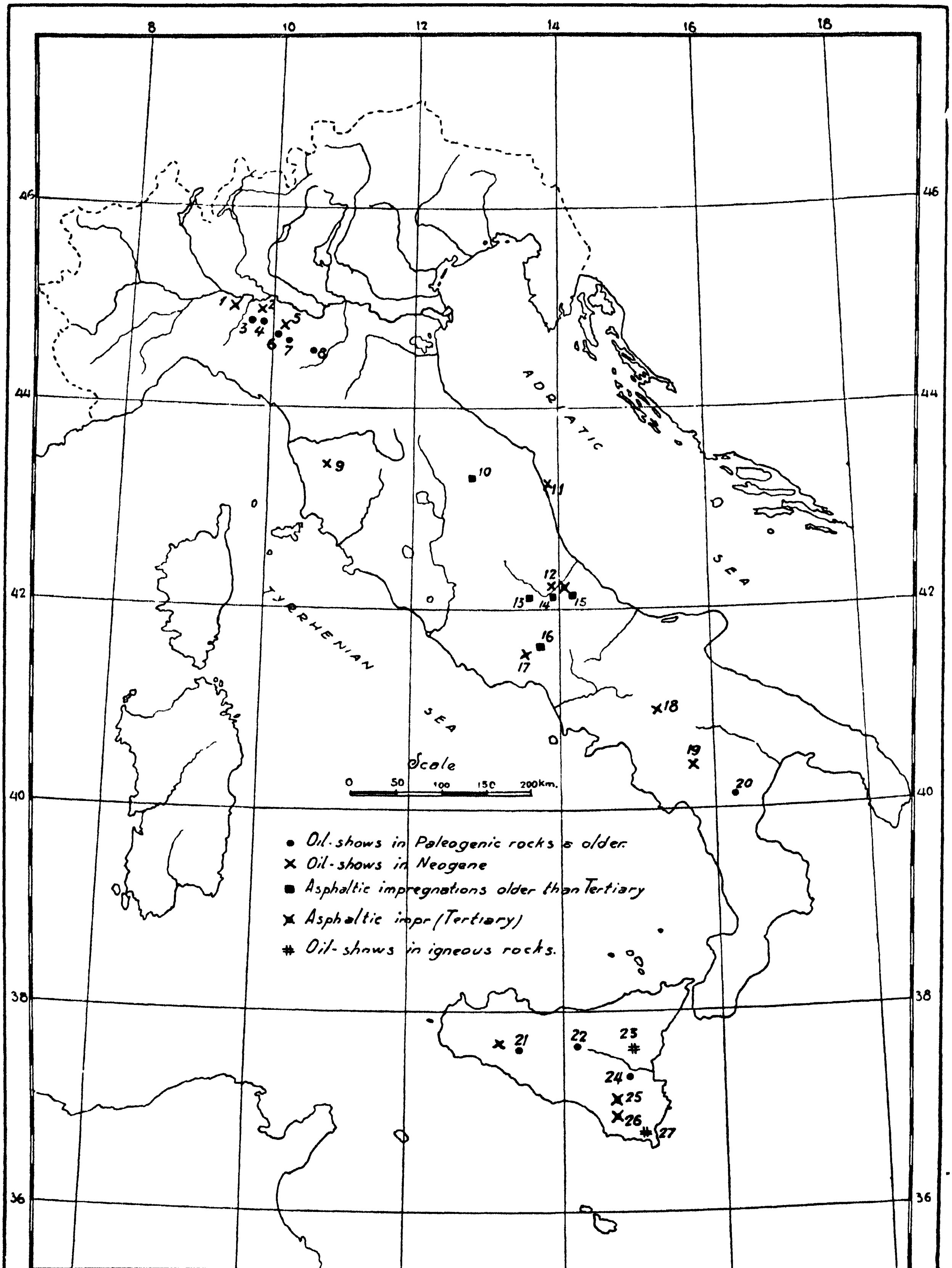

FIG. 1. Sketch-map of the main oil-shows of Italy. 1, Podenzano; 2, Carpaneto; 3, 4, Velleia a. Montechino; 5, Fontevivo; 6, Salsomaggiore; 7, Vallezza; 8, Montegibbio; 9, Volterra; 10, Gubbio (oil shales of the Lower Cretaceous); 11, Fontespina (submarine littoral oil-show); 12, Pescara Basin (oil and asphaltic impregnations); 13, 14, 15, Abruzzo Highlands; 16, Roccasecca; 17, Valle Latina S. Giovanni Incarico a. Ripi; 18, Benevento Apennine (S. Angelo dei Lombardi, Lioni, Montemarano, Casalbore, Laviano Caposele); 19, Tramutola (surroundings of Potenza); 20, Cersosimo; 21, Bivona a. Lercara; 22, Petralia; 23, Paternò; 24, Palagonia (Naftia Lake); 25, 26, Ragusa oil marls (Scicli, Ragusa, Vizzini); 27, Pachino.

of the calcareous type, eroded through the tectonic movements.

The Central and Southern Apennine oil-shows are connected with the Miocene and belong to the Mediterranean type of oil deposits. In some cases the oil-shows appear, as in the Emilian Apennine, in the tectonic 'windows' emerging from below the thrusted Mesozoic limestones. With the exception of very slight traces of oil in the Palaeogene, the structures of which are similar to the Emilian Apennine (beginning from the southern slopes of Abruzzo), the oil-shows follow the small fractured Neogene basins and depressed blocks of the area. Frequent and diffused shows of asphaltic oil are known in the **Benevento Apennine** (Upper and Lower Miocene). In this area occasional asphaltic impregnations of the Lower Eocene and Lower Cretaceous limestones reappear, and these can be considered as a continuation of the Abruzzo asphalt-bearing facies.

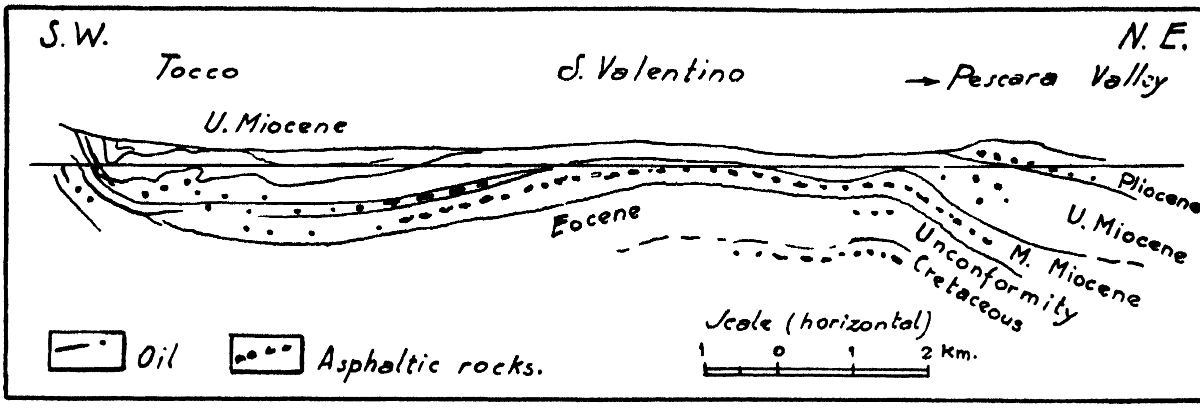

FIG. 2. Schematic section across the oil and asphalt occurrences of the Pescara Valley.

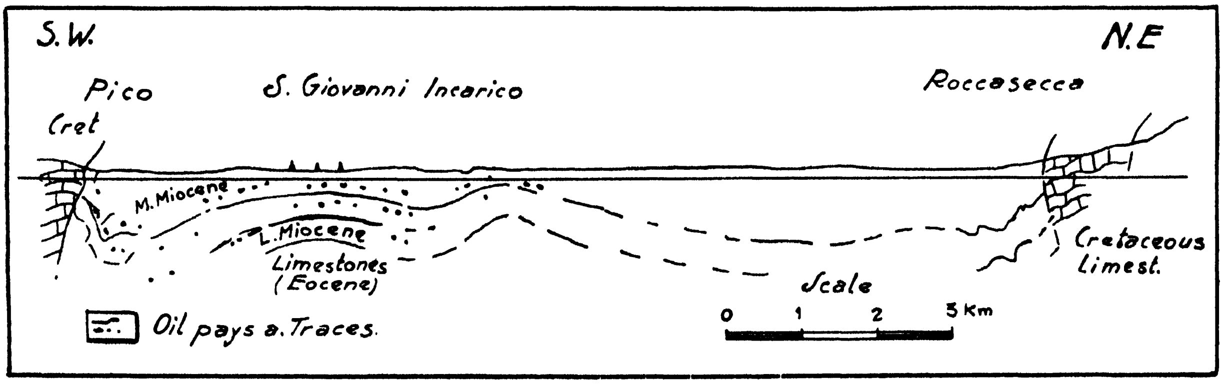

FIG. 3. Schematic section across the Valle Latina.

III. Sicily

(*a*) These comprise several small oil-shows having a certain similarity to the Emilian oil occurrences and are of a residual character in the central part of the island. Slight traces are found in the Upper Miocene (sulphur-bearing series).

(*b*) The following appearances are connected with igneous rocks.

Paternò. Very light kerosine-like oil within the cavities of a basaltic massif of the Etna system (Quaternary or recent). Its origin is probably connected with distillation from the underlying rocks (Neogene?). **Palagonia.** Mud volcano lakes with some oil on the surface and carbonic acid exhalations. Oil traces are found in the basaltic (Pliocene) rocks. **Pachino.** Cretaceous dolerites with cavities filled with asphaltic oil.

(*c*) **Asphaltic Oil-marls: Ragusa.** Large isolated impregnations occur in a Lower Miocene series covering a huge and very flat block anticline in the Sicilian Apennine foreland.

IV. Bituminous Shales

In southern Italy, as far as Sicily, bituminous shows, of Palaeogene or even Upper Miocene (Sicily) age, exist: these shows are rather isolated.

The total yearly production for Italy for the period 1932–3 was about 25,000 tons, obtained mainly from the Emilian pools.

The following scheme represents the stratigraphic subdivision of the oil-shows in Italy.

Pliocene. Slight oil-shows in the Emilian Plain.

Upper Miocene. Emilian Plain, Tuscany (traces), Pescara Basin, Benevento Apennine, Sicily (bituminous shales).

Middle Miocene. Central Italy (Pescara Valley, Valle Latina).

Lower Miocene and Upper Oligocene. Emilian Apennine, Valle Latina, Benevento Apennine, Basilicata, Ragusa (Sicily).

Palaeogene (in general). Oligocene and Upper Eocene flysch oil-shows in the Emilian Apennine, as far as Scilly. Occasional shows: Pescara Valley and Benevento Apennine; asphaltic impregnations in the limestones.

Lower Cretaceous. Extensive asphaltic impregnations in the Abruzzo-Apennine, oil shales near Gubbio, occasional shows in the Benevento-Apennine; oil-shows in igneous rocks in Sicily.

Triassic. Slight asphaltic traces in the limestones of the Alpine Range.

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FRANCE

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THE four main types of oil occurrences are distributed (Fig. 1) as follows: (1) The most recent, Palaeogene, belongs to the narrow pre-Palaeogene depressions, very flat, filled with Palaeogene oil- and asphalt-bearing deposits, and laid down on Mesozoic or even older, previously eroded basement formations. (2) Narrow folds of Mesozoic rocks, which are frequently thrusted, and local oil-bearing Triassic strata. (3) Asphaltic impregnations of Palaeogene and Mesozoic limestones, near the Western Alpine ranges. (4) Bituminous shales.

The majority of the more important shows, known up to the present time, are located between the main Variscan uplifts and the Alpine and Pyrenean ranges, i.e. in the eastern and southern provinces of France. Apart from these, the predominance of old crystalline and Palaeozoic Variscan masses deprives the country of oil. Deep prospecting to test the Palaeozoic has been discussed recently. The search for oil has already been begun in western Germany (Waterschoot v. der Gracht [5, 1935]) in order to test favourable structures in the Carboniferous or lower formations, beyond the thrusted belts and under conditions which could also be expected on the French boundaries.

1 (*a*) **Pechelbronn.** The Pechelbronn Basin represents a sector of an elongated belt known as the Rhine Valley depression (Rhine-Graben). The oil conditions of the pool, well known from the studies of de Chambrier, Gignoux, Hoffmann Haas, Kraiss, Jung, van Werveke, Wagner [7, 1930], &c., correspond exactly to those which the writer has defined as Mediterranean types. The basin forms a faulted flat depression between two Palaeozoic uplifts. The blocks, isolated by a network of oblique fractures (Fig. 2), dip towards the centre of the depression and increase in thickness in this direction. Frequent and gradual changes in the facies of single horizons from marine to brackish and fresh water are also noticed.

The Pechelbronn oil-bearing beds belong to the Oligocene and are composed of marls and shales with sand lenses. Their top is formed by dominantly marine sediments with local edge development of fresh-water limestones. The average thickness of the whole series is about 1,200 metres. Their subdivision gives three groups which, in succession, are: (1) Meletta clays, 400 metres; (2) Pechelbronn series, 400 metres; (3) Dolomitic beds. These main groups are separated from each other by clearly defined key horizons (1 : 2 foraminiferal marls, 2 : 3 red clays with gypsum). The Pechelbronn series is also subdivided into two groups, upper and lower, by the Hydrobia zone. The main sands belong to the Pechelbronn series, although local production has been obtained from the Meletta as well as from the dolomites.

The basement rocks are Jurassic and Triassic and a great unconformity exists at the base of the Rhine Oligocene. Association of saline and gypsiferous strata with the Pechelbronn oil is observed as far as the Mulhouse saline sector which has a similar sequence, and belongs to the same Graben.

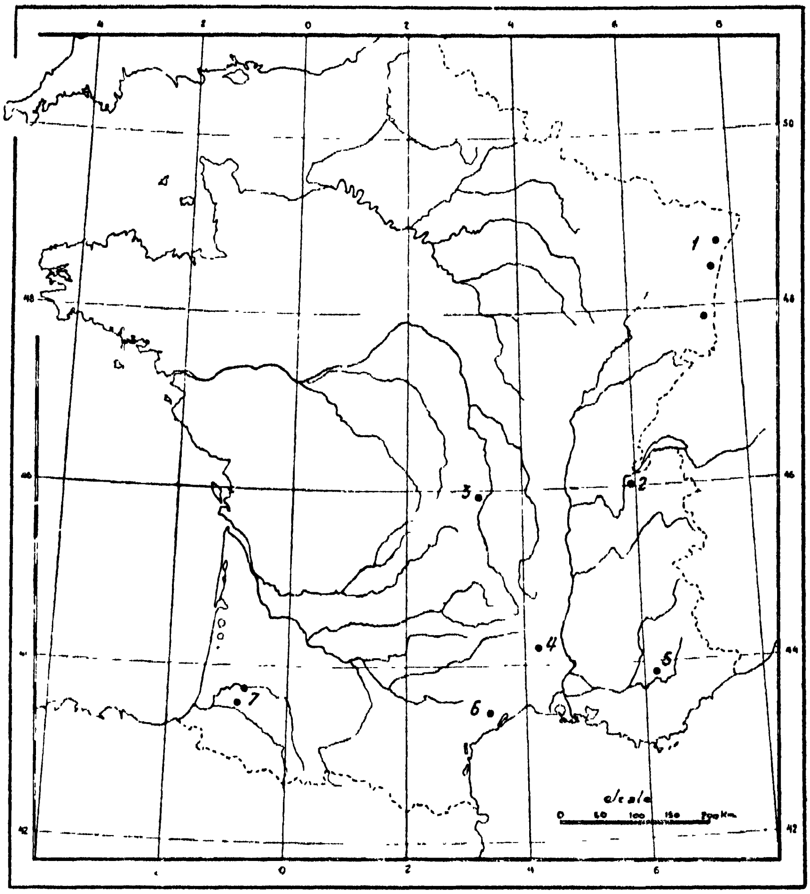

FIG. 1. Sketch-map of the main oil and asphalt occurrences of France. (Redrawn after Gignoux (simplified).) 1, Rhine Basin (Pechelbronn); 2, Savoy Basin; 3, Limagne Basin; 4, Alès Basin (Gard); 5, Manosque; 6, Gabian Pool; 7, Sub-Pyrenean belt.

Occasional oil occurrences, sometimes productive, have been found in the Dogger limestones at the base of the Graben. The oil-bearing Oligocene is considered to be associated with these.

As a consequence of the lack of favourable structures in the block faulted, estuarine strata, the oil distribution is lenticular with complete isolation of individual lenses. Light paraffinic oils predominate (sp. gr. 0·860 and more), although the heavy types are also frequent (up to 0·975). The asphaltic impregnations at Lobsann are considered by Haas and Hoffmann as secondary and due to seepages during the Upper Oligocene period.

The oil production is obtained from wells and galleries (60,000 tons and more per year).

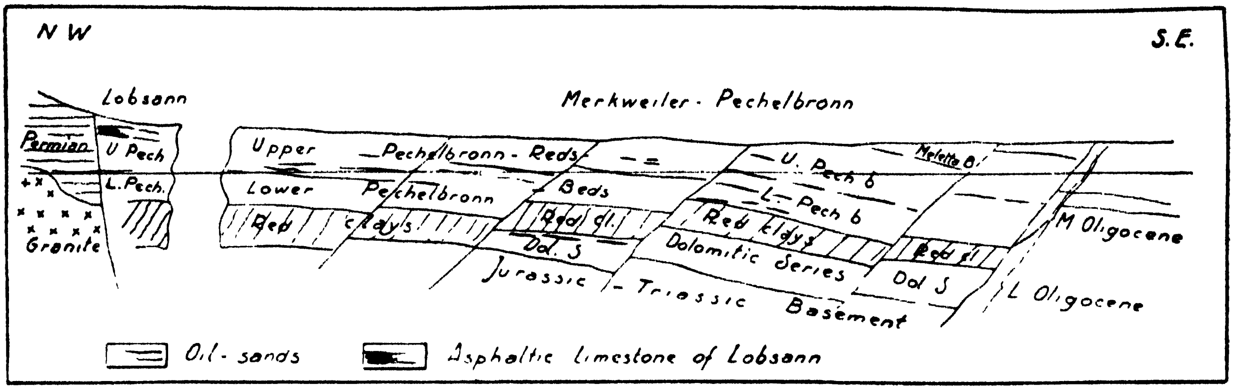

FIG. 2. Section across the Pechelbronn Pool. (Redrawn after Haas and Gignoux (simplified).)

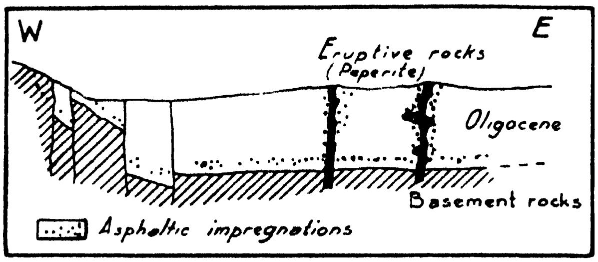

FIG. 3. Ideal section explaining conditions of asphalt deposits of the Limagne Basin. (*After Gignoux.*)

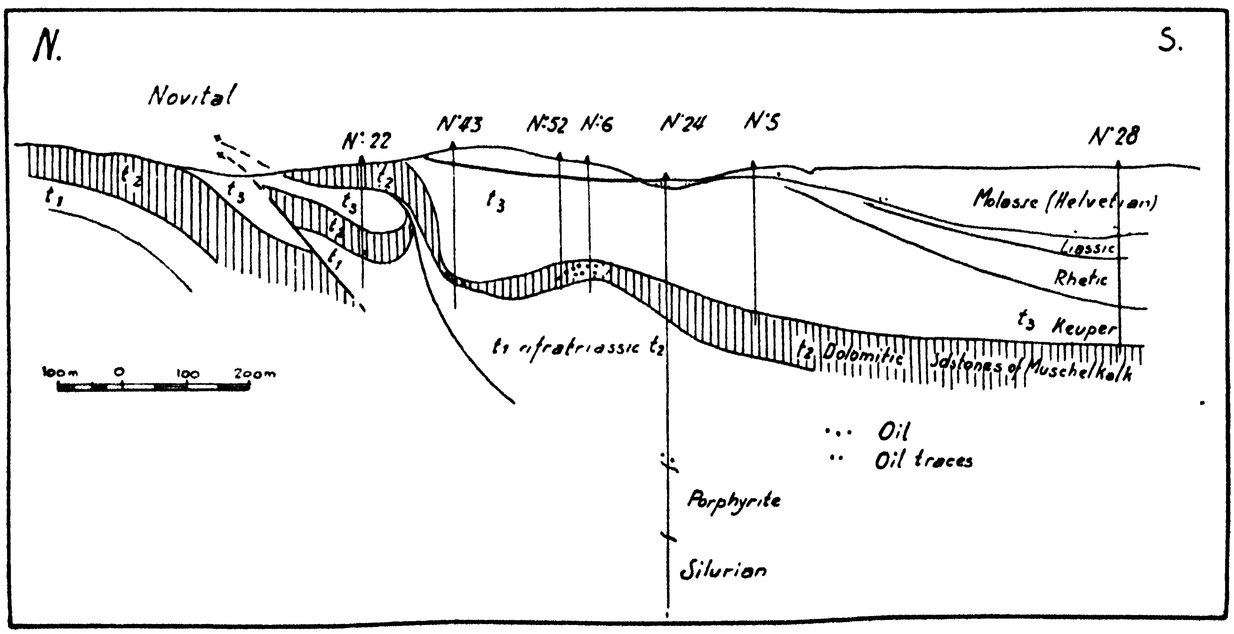

FIG 4. Section across the Gabian Pool. (Redrawn and completed after Barrabé and Schneegans.)

1 (*b*) **The Asphalt-bearing Molasse Basin of Savoy** has impregnations in the Oligocene beds and adjacent unconformably covered Urgonian limestones.

1 (*c*) **The Limagne-Graben Depression** (Fig. 3) is a depression of Mediterranean type filled with Oligocene sediments and frequently pierced by perperite dykes. Asphaltic impregnations are distributed near the basal unconformity and rise vertically near the eruptive dykes.

2. **Triassic Occurrences in the Sub-Pyrenean Zone** are connected with highly disturbed beds of Upper Triassic (Keuper) age, referred to by Viennot [6, 1930]. The well-known **Gabian Pool** is located in a system of narrow, thrusted overfolds in the centre of which an oil sand occurs on the top of an anticlinal fold in the Muschelkalk (Middle Triassic) breccia (Fig. 4). Conditions in the oil-bearing formation, described by Barrabé and Schneegans [1, 1935], prove that there is a residual accumulation of oil localized on the top of the fold with the edge-waters closely occupying its slopes.

Although limited in extent, the Gabian oil-pool has given a good production of light paraffinous oil, 0·846 sp. gr. (up to 1934, 24,000 tons). Notwithstanding the somewhat erratic and highly disturbed character of the Triassic oil-shows of southern France they permit the supposition of a much larger extension of the whole belt from the Atlantic coast up to the Rhone Valley.

3–4. Bituminous and asphalt-bearing limestones and shales are known in several localities in France associated with formations from the Palaeogene down to the Carboniferous. They frequently show association with bituminous coals. From the oil-prospecting point of view and in view of the palaeogeographical conditions they are phenomena of primary importance.

The stratigraphic conditions of the oil occurrences in France are as follows:

Oligocene. Main oil- and asphalt-bearing formations Alsace (Eocene) Limagne Savoy.

Cretaceous–Jurassic. Occasionally asphalt bearing.

Triassic. Sub-Pyrenean oil shows.

Upper Palaeozoic. Occasional development of bituminous shales.

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SECTION 5

MIGRATION OF PETROLEUM

THE MEASUREMENT OF THE PERMEABILITY OF RESERVOIR ROCKS AND ITS APPLICATION

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The Concept of Permeability

PERMEABILITY is a term which refers to the relationship between the pressure gradient and the resulting rate of flow of fluid through porous materials. As experimental knowledge has increased this concept has undergone subdivision and refinement, so that at present the term permeability will often need a qualifying adjective, such as 'viscous', 'turbulent', 'relative', 'dynamic', or 'stable mixture' permeability. These makeshifts may eventually give way to special terms, but while current experiments are bringing new facts within the range of use it will be important to define permeability carefully.

At present the most common technical meaning of permeability is the constant K which occurs in Darcy's equation [3, 1856] for the viscous flow of a single, homogeneous fluid.

$$\frac{dQ}{dt} = \frac{K}{Z}\frac{dP}{dx}. \tag{1}$$

If in this equation dQ/dt is the rate of passage of fluid per square centimetre of equal pressure surface, Z is the viscosity in centipoises, and dP/dx is the gradient of pressure in atmospheres per centimetre, then K will be expressed in terms of the Darcy unit of permeability as adopted in 1935 by the American Petroleum Institute [1, 1935]. The permeability is thus defined *only for viscous flow and for a single fluid*, on which basis the experimental background is quite adequate [17, 1899; 39, 1934]. However, such a permeability as this ordinarily is not satisfactory for precise calculation in an oilfield. With few exceptions, producing fields contain mixtures of oil and gas, and sometimes salt water as well. In discussing the flow problems of oil production it is important to bear in mind that permeabilities as measured in the laboratory apply only to slow or viscous flow of single fluids, while in practically every field case either immiscible fluids are present or the flow is sufficiently rapid to result in turbulence. Although the flow in the greater part of the *area* of an oilfield is certainly non-turbulent, a considerable part of the pressure drop takes place near the well at such velocities that flow of the gas, at least, is definitely turbulent.

These facts demand that new experiments be made and new concepts be carved out to deal with mixtures and with turbulent flow.

Definitions of symbols used appear at the end of this article.

The Darcy Coefficient of Permeability

Laboratory Procedures.

Recent progress in laboratory technique for measuring the Darcy coefficient has been in the nature of refinement of apparatus rather than fundamental change. The work of Fancher, Lewis, and Barnes [6, 1933] at the Pennsylvania State College, and of Wyckoff, Botset, Muskat, and Reed [39, 1934] at the Gulf Research Laboratory laid down a foundation of good practice which has been improved only in the direction of minor details which speed up the work rather than improve accuracy. Faster procedure has come to be important in secondary recovery work because the charge of explosive which is used in producing wells should be proportioned in accordance with the laboratory measurements of permeability. Since the hole must be shot before the well is finished, the drilling crew is often idle until the measurements made on the core are returned from the laboratory.

It has been found in the laboratory that most of the time is consumed in drilling out from the core the small test specimens and in calculating the results. Certain improvements in procedure may be worth recording here.

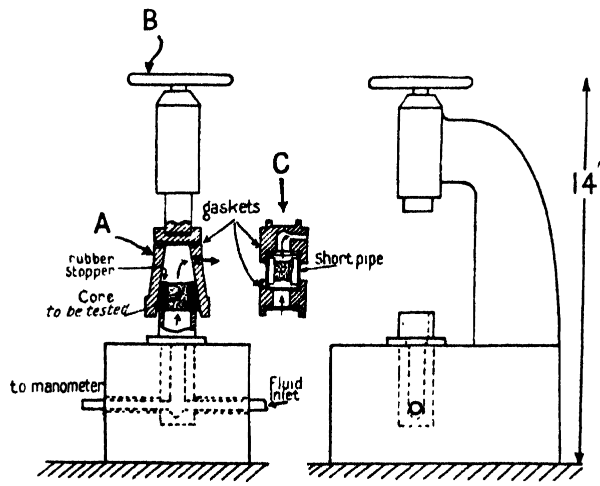

FIG. 1. Quick-change core holder for permeameter.

In mounting the core in the drill press the rock is best embedded in low-melting alloy such as 'woods metal' or other alloy melting below the boiling-point of water. Higher temperatures are undesirable because of possible effects on permeability [14, 1930]. A long double-jacketed vessel which can quickly be heated and cooled with steam or cold water and which can be handled easily on the drill press will speed up the job of obtaining test specimens by drilling with abrasives. For close work with small fragments, as of the 'biscuit' core material, diamond-set tubes of diameter as small as $\frac{1}{8}$ in. are sometimes used. The drill press should be substantial and should permit a wide choice of speeds.

In mounting these specimens for the flow test (generally with air) the method developed by Fancher is now universally used, the sample being placed in a rubber stopper suitably cut out to receive it and then compressed in the rubber by forcing the stopper into a brass cone. The latest type of permeameter holder as built in the shops of the Pennsylvania State College is illustrated in Fig. 1. The design, which is principally due to the shop foreman Mr. E. F. Sheeder, permits rapid insertion and

withdrawal of the conical core holder *A* by spinning the screw handle *B*. The auxiliary holder *C* is used in those rare cases where an irregularly shaped specimen must be set in wax or Wood's metal.

The work of reducing the data for each individual sample (generally obtained in centimetres of mercury pressure, length and diameter, centipoises of viscosity, millilitres of gas received, and seconds of time of test) may be shortened by the use of a nomographic chart [18, 1936].

The fluid used in these measurements is almost invariably dry air, and the pressures should be the lowest for which a measurable rate of flow is obtained. Special permeability studies are occasionally made with the flooding water which is used on the lease concerned; these are sometimes described as 'water permeabilities' and are generally lower than the 'dry permeabilities' because of the swelling of cementing material.

The specimen is prepared for test by extracting the oil with benzol or a low-boiling naphtha in preference to carbon tetrachloride. It has been found (unpublished work by E. S. Hill at the Pennsylvania State College—petroleum production laboratory) that during carbon tetrachloride extractions a definitely acid condition develops which is dangerous to the cementing material of a permeability sample.

Information obtained from Microscopic Examination or Mechanical Analysis of Sandstones.

The only dependable way of determining the permeability of a rock is to measure it directly by comparing the rate of flow of a fluid with the corresponding pressure gradient. This method will also take considerably less time than carefully performed mechanical analyses. However, there are certain cases where the taking of suitable cores is not practicable, where material suitable for grain-size analysis is available without cost, and in which previous direct measurements on diamond cores in the same property provide a primary standard which can be compared with the results of grain-size analysis. In such cases it may be feasible to measure the shot and set the packers for flooding or gas drive in accordance with grain-size measurements. A recent paper by Ryder [30, 1936] gives a suitable procedure and formula for Bradford sands which has had practical application.

It appears that the examination of the rock with a view to locating the direction of alinement of elongated grains may give valuable information about the directional asymmetry of permeability in any given field. It is known that in some fields the flow takes place more easily in one direction than in another [13, 1935] and that greater production can be obtained from secondary recovery operations in which the well spacings are made greater in the direction in which the permeability is greatest [13, 1935; 37, 1936]. This sorting as to shape may be a geological factor of considerable importance in properties whose reservoir contains pebbles in quantity.

When grains are packed against an unyielding wall, as of lead shot against the wall of a beaker, or silica grains against a larger smooth pebble, the porosity of the layer will be increased and the permeability along the boundary will be greatly increased [8, 1935]. It follows, therefore, that in those cases in which the larger asymmetrical grains are oriented by stream or wave action, these boundaries will cause an asymmetrical permeability condition in which the greatest permeability is in a direction at right angles to the direction of the old currents. In a similar way the occurrence of plates of mica, which generally lie parallel with the bedding plane, will mean that abnormally low flow-resistance will be found in the bedding plane. These can be seen readily by causing a fractured surface to bubble air under water. The larger plate of mica, as in Bradford sandstone, will be marked by profuse bubbling along each side of the plate. There is evidence that where this condition is prominent, a microscopic by-passing of oil by the flooding water will take place which may be serious [31].

It is believed that in such accessory items of geological knowledge as this the microscopic analysis of sand grain-size and shape will be important. It should be emphasized, however, that the best way to determine permeability for control of field operations is to core the wells and make direct measurements as described by the A.P.I. tentative standard [1, 1935]. Many excellent papers have been published which attempt to relate porosity and grain-size studies to permeability by elaborate empirical study and theoretical deduction [32, 1932; 7, 1934; 4, 1933], but their importance is in their value as research studies; their value lies largely in their indirect bearing upon wider problems than the determination of the Darcy coefficient of permeability.

The Uses to which a Knowledge of Permeability can be put in Secondary Recovery.

In water flooding or air-gas drive recovery properties the principal purpose of engineering control is so to adjust the spacing of the wells and the position of packers that the driving fluid will be distributed in equal proportion to all parts of the oilfield. A knowledge of permeability conditions is indispensable in deciding these questions. In most cases a failure to learn and understand the permeability distribution will result in a serious loss.

Correct practice in spacing water flood-wells is not yet clearly defined because of our lack of knowledge of the effective fluid resistance and efficiency of the main body of the reservoir. There seems to be no recognized difference in the efficiencies of wide spacings and short spacings of the wells; it is said that a water flood will recover from 35 to 45% of the oil in the sands [5, 1936] without bias as to spacing. Where beds are lenticular it is felt that the spacing should be close enough to avoid the possibility of driving the oil into pockets where the sand is pinched out between shale, but in general, the limiting factor is the length of time involved before a return is gained on the investment [2, 1936]. If the spacing is too wide, the flood may take as long as ten years to reach completion.

The first intensive floods in the Bradford field used close well-spacings—from 200 to 250 ft. between water-wells—but this spacing has been gradually increased [33, 1930] until spacings of from 300 to 450 ft. between water-wells are not uncommon for sands averaging 10 millidarcies. When permeabilities reach 3 or 4 millidarcies it is well to reduce spacings [2, 1936]. The present practice in the Mid-Continent field may be typified by the Alluwe field, Rogers County, Oklahoma, where permeabilities range around 20 millidarcies and the kinematic viscosity of the oil is about 10 centistokes. The spacing chosen is 440 ft. from water-well to water-well [5, 1936] in a five-spot development. An average of from 40 to 50 bbl. of water per day at a pressure of 400 lb. per sq. in. is allowed each input well.

The application of permeability profiles (curves of permeability against depth) to the setting of packers may be

illustrated best by an example. In Allegany County, New York, is a property where two sands are encountered, the upper sand having a permeability averaging 4 millidarcies and an oil content of 3,900 bbl. per acre, while the lower sand has permeability averaging 65 millidarcies and oil content of 8,000 bbl. per acre. When both sands are flooded together at a pressure of 900 lb. per sq. in. the recovery is about 2,900 bbl. per acre. By using two strings of tubing to apply a pressure of 1,500 lb. on the upper sand and 600 lb. on the lower sand, the recovery is raised to 4,500 bbl. per acre [2, 1936].

Such qualitative applications of the permeability as these examples illustrate do not require elaborate calculation since the use of the information is quite obvious. The importance of these applications of permeability measurement will increase as better techniques for acid treatment and chemical plugging of reservoir [16, 1936] rock make it possible to alter the effective permeability in such a way as to produce the desired permeability profile in the well.

The More Recent Experimental Developments of the Concept of Permeability

The above-mentioned control of well spacing and of the setting of packers is only very rough at present because the resistance to flow in an oilfield is not of the single fluid, viscous type. The assumption has been made that the resistance which a sand offers to the flow of mixtures will be about proportional to the Darcy coefficient of permeability. Some companies have developed empirical formulas for the specific intake of new water-wells, probably based on the unit conductivity formulas given by Muskat and Wyckoff [25, 1933] which sum up the results of field experience with permeabilities, pressures, and spacings, and these formulas use that assumption successfully.

Recently research workers have become interested in the effect of turbulent flow and of the presence of mixtures. The following paragraphs attempt to co-ordinate the available results of this work.

Turbulent Flow in Porous Rock.

It is known from studies of the flow of liquids in cylindrical tubes that turbulent motion occurs when the 'Reynolds number' (or ratio of inertia factors to viscosity) exceeds a critical value. One could predict from this experience that the flow of gases in a sandstone whose grains are large and angular would become turbulent more readily than in sandstone whose grains are rounded and well cemented. This is indeed the case. However, the phenomenon of 'critical velocity', at which the flow character changes sharply from streamline to turbulent, does not occur in permeable media. Instead, the transition is so smooth that it is hard to decide where the element of turbulence first enters.

If in equation (1) above Q is replaced by V, a volume of gas measured at an arbitrary pressure P, the resulting equation is

$$\frac{dV}{dt} = \frac{K}{Z}\frac{dP}{dx}. \tag{2}$$

Upon substituting Boyle's law, writing P_2, V_2 for the outlet pressure and volume,

$$\frac{dV}{dt} = \frac{P_2}{P}\frac{dV_2}{dt}. \tag{3}$$

We thus obtain

$$P_2\frac{dV_2}{dt} = \frac{K}{Z}\left(P\frac{dP}{dx}\right) = \frac{K}{2Z}\frac{d}{dx}(P^2). \tag{4}$$

In any actual measurement the inlet pressure P_1 and the outlet pressure P_2 (generally atmospheric) will be held constant so that dV_2/dt, the rate of flow of outlet gas at the measuring pressure P_2 will be constant.

Under these conditions it is clear from equation (4) that $d(P^2)/dx$ must be constant.

Thus the Darcy law of viscous flow for gases should take the integrated form

$$\frac{V_2}{t} = \frac{K}{2ZxP_2}(P_1^2-P_2^2), \tag{5}$$

where V_2 is the outlet volume of gas collected in time t, x is the length of the cylindrical flow specimen, and P_1 is the inlet pressure.

Equation (5) is commonly handled by reducing V_2 to the mean volume V_m. Thus, upon writing $P_1^2-P_2^2 = (P_1-P_2)(P_1+P_2)$ (5) becomes

$$\frac{V_m}{t} = \left(\frac{2P_2}{P_1+P_2}\right)\frac{V_2}{t} = \frac{K}{Zx}(P_1-P_2). \tag{5a}$$

It is found by experiment [9, 1929; 24, 1931; 27, 1935] with the flow of gases in sandstone, and in tubes packed with sand, beads, &c., that,

$$\left(\frac{V_2}{t}\right)^n = \frac{C}{X}\ (P_1^2-P_2^2), \tag{6}$$

where the exponent n may have any value from unity for viscous flow conditions to two for the completely turbulent condition. The constant C involves the viscosity, but not the viscous permeability. It will be found that the exponent n is independent of the external dimensions of the flowing medium [27, 1935] but depends rather on the porosity, angularity, and size of the grains which form the medium. Anything which restricts turbulence reduces n [24, 1931]. Smooth surfaces of the grains or of the cementing material and restricted size of capillary spaces tend to limit the formation of those microscopic eddies which presumably are associated with turbulent flow.

It may be assumed that the smooth change in the value of n from one towards two as the velocity of flow is increased is the composite effect of a great many sharp, critical changes from lamellar to turbulent flow in separate channels of the sand. If the rates of flow and pressure gradients of any chosen microscopic capillary could be plotted there must be a reasonably sharp transition, for this is a general characteristic of fluid flow.

It is because the factors which determine the value of n are not only *microscopic* but also involve a very complicated relationship with the flow properties that one cannot readily correlate n with measurable properties of the sandstone. The flow which is measured in the laboratory is the sum of the contributions of a great many sizes and, perhaps, types of holes, which are connected in series as well as in parallel. The proportion of larger channels in the sandstone would seem to be a very important item in determining the type of flow, for if the larger holes carry the greater part of the gas turbulence in them will control the value of n for the specimen as a whole.

Consider, for example, two specimens of consolidated sandstone having the same porosity, the same viscous flow permeability (by viscous flow permeability is meant the constant K of equation (1), measured at very low-

pressure gradients so as to avoid turbulence) and the same chemical character. Of these two specimens one may have a frequency distribution of capillary sizes such that there are a few abnormally large holes—say a hundred per square centimetre—which the accidental cementation has left open. These will carry practically all of the gas. The other core may have an abnormal number of open middle-sized pores, without any large ones at all. It is obvious that the first core will have a very high velocity of flow in the few large holes, while the second core will have a relatively low velocity in a great many small holes. The first core will therefore give a very turbulent flow with high values of the exponent n at low-pressure gradients, while the second core will persist in its viscous-flow condition up to extremely high values of the pressure gradient.

If it can be shown to be generally true that for a given permeability a high value of n at low-pressure gradients means a heterogeneous or skewed distribution of capillary sizes, then the measurement of n may be important not only from the standpoint of calculations of gas flow but also from the point of view of oil recovery. At present it seems probable that if the gas escapes through a few large holes it will not be as effective in transporting oil as it would be if the energy were distributed more uniformly among the oil-bearing holes of the rock. A sand which is good from the standpoint of secondary recovery is of uniform texture [7, 1934], i.e. it has oil-bearing pores which are also fluid conducting channels. If our analysis is correct, a low value of n may be an indicator of this condition.

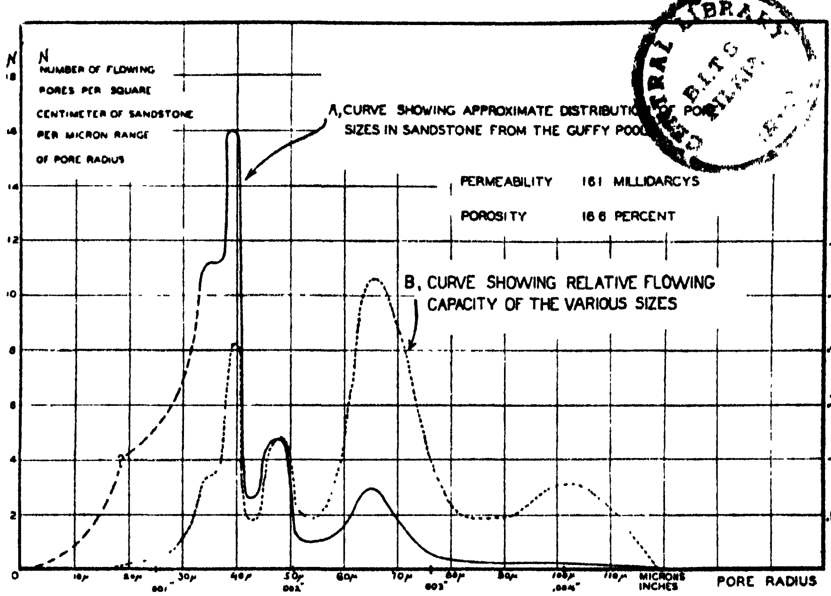

FIG. 2. Curve A is inferred from experimental data on the number of bubbling spots per square centimetre and the corresponding capillary back pressure, when a fractured face was bubbled under water. Curve B is calculated from curve A by assuming that Poiseuille's fourth power law can be used. The area under curve B is proportional to the permeability.

Fig. 2 shows the result of an initial attempt to extend our information about sandstone permeability by measuring the flowing capacity of the *separate hole sizes* of a piece of Bradford sandstone having a permeability of 16 millidarcies. Curve A was measured by comparing the number of bubbling-points per square centimetre at a fractured surface-flowing gas under water with the capillary back pressure developed at the surface for a number of rates of flow. Curve B shows the relative carrying power of the various capillary size ranges on the assumption that the flow through each capillary is proportional to the fourth power of its radius (Poiseuille's law). Large capillaries of course are restricted by other smaller capillaries which are connected in series with them, but curve B would seem to emphasize the relative importance of the larger sizes. The salient feature of curve A is that there are well-defined critical size ranges in which the concentration of capillaries is high. Whether these 'peaks' will persist among other samples of the same sand is not known. Curve B shows that one-half of the carrying capacity of a fractured section is in about one-twentieth of the capillaries, and 90% of the carrying capacity is in capillaries numbering less than 1 per sq. millimetre. This work has not yet been carried forward far enough to prove the relationship suggested above between n and the frequency distribution of capillary sizes.

It may be predicted that such a relationship cannot be exact because the critical velocity at which turbulence is encountered in any tube depends not alone on the size but also on the roughness of the wall and the shape of the tube.

In most cases it will be sufficient to regard both the permeability factor K and the velocity exponent n as constants. Thus Rawlins and Schellhardt [28, 1935] find that data obtained on 582 gas-wells throughout the United States can be represented adequately by the above formula (6) if suitable precautions are taken to make P_2 equal to the actual pressure at the face of the sand and P_1 the true formation pressure. They write their formula

$$\frac{dQ}{dt} = C(P_1^2 - P_2^2)^m, \tag{7}$$

where dQ/dt = rate of flow, cu. ft. per 24 hours,

C = constant,

P_1 = shut in formation pressure, lb. per sq. in. absolute.

P_2, back pressure at the face of the sand in the well bore, lb. per sq. in. absolute.

m is an exponent corresponding to the slope of the straight line relationship between Q and $P_1^2 - P_2^2$ plotted on logarithmic paper.

It should be noted that the m of this expression is the reciprocal of the n of equation (6), and that the constant C includes the permeability, viscosity, and back pressure together with an indeterminable shape factor which depends on the geological peculiarities and the distribution of fluid in the producing sand. Rawlins and Schellhardt further assert that it is necessary to conduct tests at reasonably long intervals on gas-wells to determine new values of m and C. These authors believe that the value of m does not change with the pressure gradient [29, 1935], but feel that a change in m involves a change in the physical condition of the sands. Their curves show quite appreciable changes in the slope m, however, and it is clear that by 'negligible' changes in m these authors mean that

they are not significant for the ordinary purposes of gauging gas-wells.

For a discussion of the relationship between the permeability K and the exponent $n = (1/m)$, however, Muskat and Botset [24, 1931] offer data on glass beads, in which the slope (see Fig. 3) changes from $n = 1$ to $n = 1{\cdot}5$ with no cause other than the change in pressure gradient. Under these conditions they remark that the concept of permeability is not well defined. For if the equation

$$\rho v = \frac{K}{Z}\left(\frac{d}{dx}(P^2)\right)^{\frac{1}{n}} \tag{8}$$

be solved for K by substituting ρv (the mass velocity) and $d(P^2)/dx$, using these and $1/n$ obtained from the point under consideration, the value of K is not a constant at all. It was found from Fig. 3 by this process that when

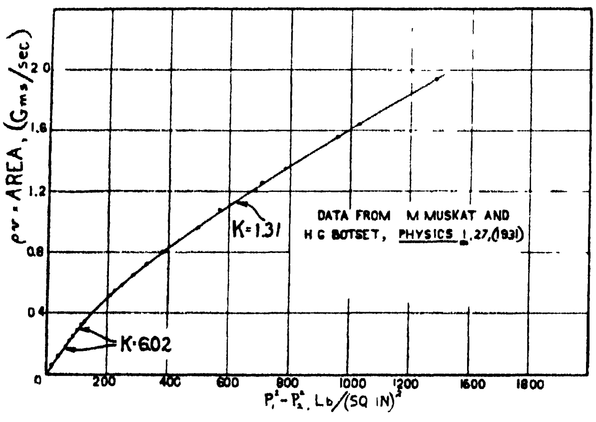

FIG. 3. Data showing increase in turbulence with pressure gradient. When plotted on logarithmic coordinates, the value of the slope n is 1·0 where $K = 6{\cdot}02$ and 1·5 where $K = 1{\cdot}31$.

n rose from 1 to 1·5, K decreased from 6·00 to 1·31. Therefore since the 'permeability' is conceived as an invariant physical property of the medium, it appears that a definition of 'turbulent' permeability is wanted. Since true permeability is not the physical constant which occurs in the C of equation (6), when n is greater than one, the difference being some hundreds per cent., one must be careful not to use a permeability constant determined at very low-pressure gradients in flow calculations where n is appreciably greater than one [1, 1935].

A frequency distribution curve showing the occurrence of the various ranges of this exponent is plotted in Fig. 4. The curve is probably the most extensive set of flow data in existence on the character of reservoir sands from the strictly flow point of view. The surprising thing about it is that so many values of n, as actually measured on hundreds of wells in the field, are definitely less than unity. It is a commonly accepted dogma of laboratory experience that n must lie between one and two—one represents purely viscous flow and two represents completely turbulent flow. Fig. 4 shows that there is a reasonably complete lack of wells whose exponents n are greater than 2; only 5 wells out of 582 have exponents greater than that which means pure turbulence. But 173 wells have exponents less than that which means purely viscous flow. How can one account for an increase in flow with pressure gradient, which is even greater than linear, occurring frequently enough to be called a normal condition of flow?

It is believed that these data may be accounted for by assuming that heavy gaseous hydrocarbons exist as liquids in the reservoir rock adjacent to the well at high pressures, but flash into gases within the formation as they approach the well. Since the disappearance of liquid from the rock reduces the resistance to flow, it is possible that this resistance will be reduced systematically as the well pressure is reduced in such a way that a plot of production rate against the difference in the squares of the pressure will

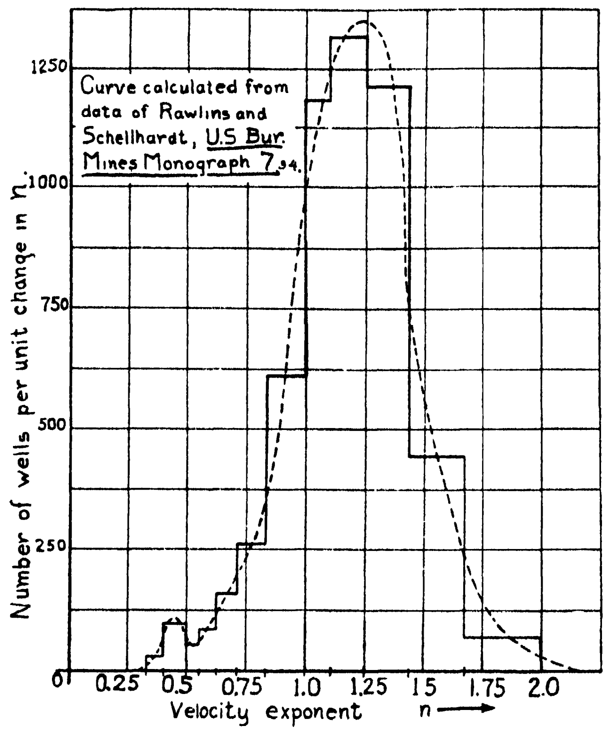

FIG. 4. Curve showing frequency distribution of n in the formula $(V/t)^n = P_1^2 - P_2^2$ as measured in a widely distributed group of 582 gas-wells. For example, the number of wells per unit change in n between 1·0 and 1·11 is plotted as 1,181. Multiplying by the change in n, namely, 0·11, we obtain 130, which number Rawlins and Schellhardt observed.

still be a straight line on logarithmic paper, even though n becomes less than one. Before examining this possibility quantitatively a short discussion of the effect of liquid in sandstone on the permeability will be presented.

The Effect of the Presence of Liquid on the Permeability to Gas.

Recent work concerning the effect on the permeability of the presence of liquids in sandstone and packed sand has established the following points:

1. The liquid in the sandstone is effectively locked to the pore walls so that the combination acts upon gases as if it were dry sand of reduced permeability [10, 1936].

2. The permeability of the wet sandstone depends on the dry permeability and the per cent. saturation in a reproducible way [11, 1936] as shown in Fig. 5 (curve A). Knowing any two of these factors it is now possible to make a reasonably accurate calculation of the other. The empirical equation

$$K(s) = Ke^{-7{\cdot}75\, s^{2{\cdot}25}} \tag{9}$$

approximates this relation for Bradford sandstone. Here $K(s)$ is the permeability to gas at saturation s.

3. When gas is driven through a length of oil-soaked sandstone the oil is removed at a rate which decreases very

rapidly when the saturation decreases. The gas-oil ratio decreases exponentially with increasing saturation. For Bradford sandstone we have approximately

$$\frac{dV}{dq}=\frac{10^{(6\cdot9-8\cdot6s)}}{\sqrt{1/Z}}. \tag{10}$$

where dV/dq is in cubic feet of gas per barrel of oil passing any section of sand.

Here Z = viscosity of oil in centipoises.

flow of gas with pressure gradient is in every case similar to that of dry sand. For low-pressure gradients Darcy's law is followed. Fig. 6 shows data on this point, and the data of curve A, Fig. 5, indicate that it is true over a wide range of saturations. These data were obtained by driving Bradford sandstone cores with air. The cores were small and the saturations could be determined readily by weighing on a chemical balance.

Data for which the saturations are not quite so well stated are reproduced in Fig. 7. A vertical 1½-in pipe 20 in. long was filled with 20–30-mesh river sand and driven with air at high pressure, first as dry sand, then after adding various quantities of oil. The curves of Fig. 7 show plots, on logarithmic co-ordinates, of $P_1^2-P_2^2$ against rate of flow of gas. It will be observed that the oil-wet sand yields straight lines as does the dry sand, and shows the same slope as the dry sand curves. The only difference is in the value of C as defined in equation (7) above, and since the shape of the flow tube does not change one must conclude that the stable 'specific conductivity' or permeability for oil-wet river sand, 20–30 mesh, is about 73% of the dry permeability no matter what the pressure gradient is. The similar slope and straightness of line of the various curves

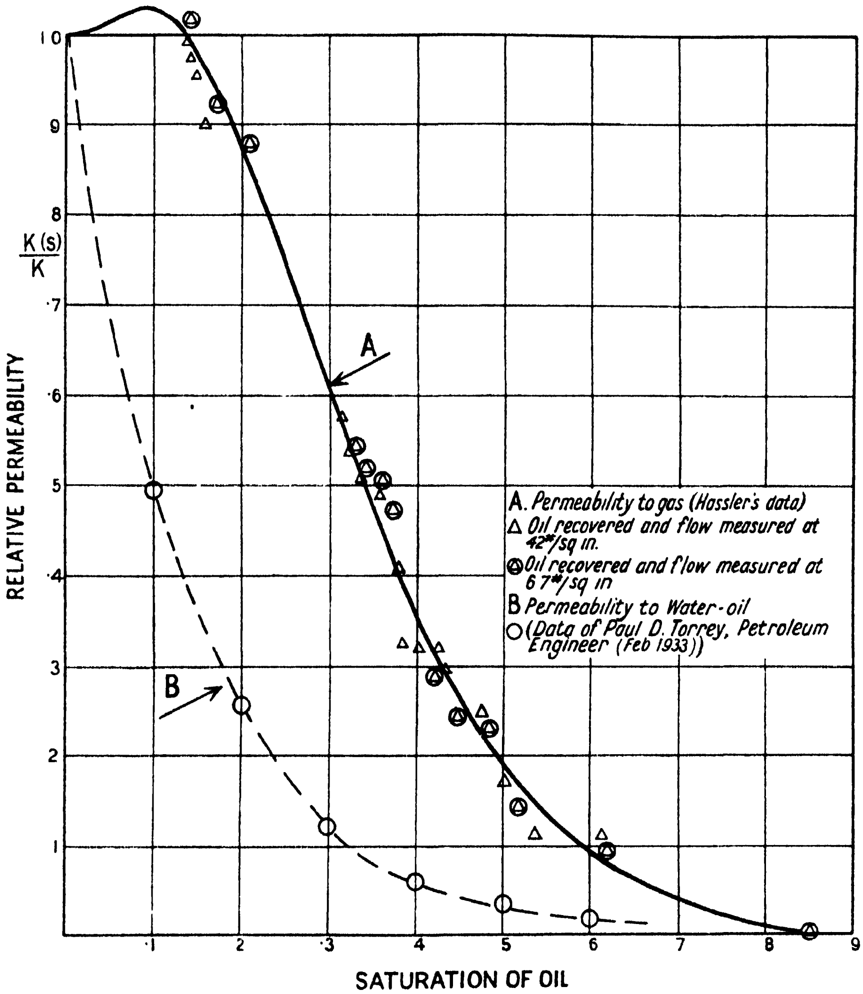

FIG. 5. Curves showing the permeability of sandstone containing (A) oil-air mixtures and (B) oil-water mixtures. The most probable form of curve A is given by equation (9). Curve B seems to be the only published data of this kind. $K(s)$ here refers to the rate of flow of total fluid (both oil and water). No pressure stated.

4. As a result of statements 1, 2, and 3 above, when oil which bears gas in solution is forced through a length of sandstone, the effective permeability near the outlet quickly approaches a stable value. From the number of cubic feet of dissolved gas per barrel of oil an equation such as (10) above can be used to determine the stable saturation. Hence, through equation (9) it is possible to determine the stable permeability to gas.

5. When dry gas is forced through oil-wet sandstone, the rate of oil transfer decreases so rapidly that the sand will appear to approach a stable saturation and a stable permeability to gas.

The statement that the liquid acts as part of the rock may be justified by the fact that the variation of rate of

of Fig. 7 seem to mean that the oil in the sand occupies the same position in the sand during the high rates of flow as it does during the low rates of flow, or, as stated above, it acts upon the gas as if it were a solid part of the porous medium.

The fact that the curves of Fig. 7 approach an asymptotic position near line D may be accounted for by assuming that all oil in excess of the saturation which corresponds to the asymptotic position (about 30%) is quickly driven out of the flow tube by the driving air, the remaining loss of oil being negligible as implied by equation (10).

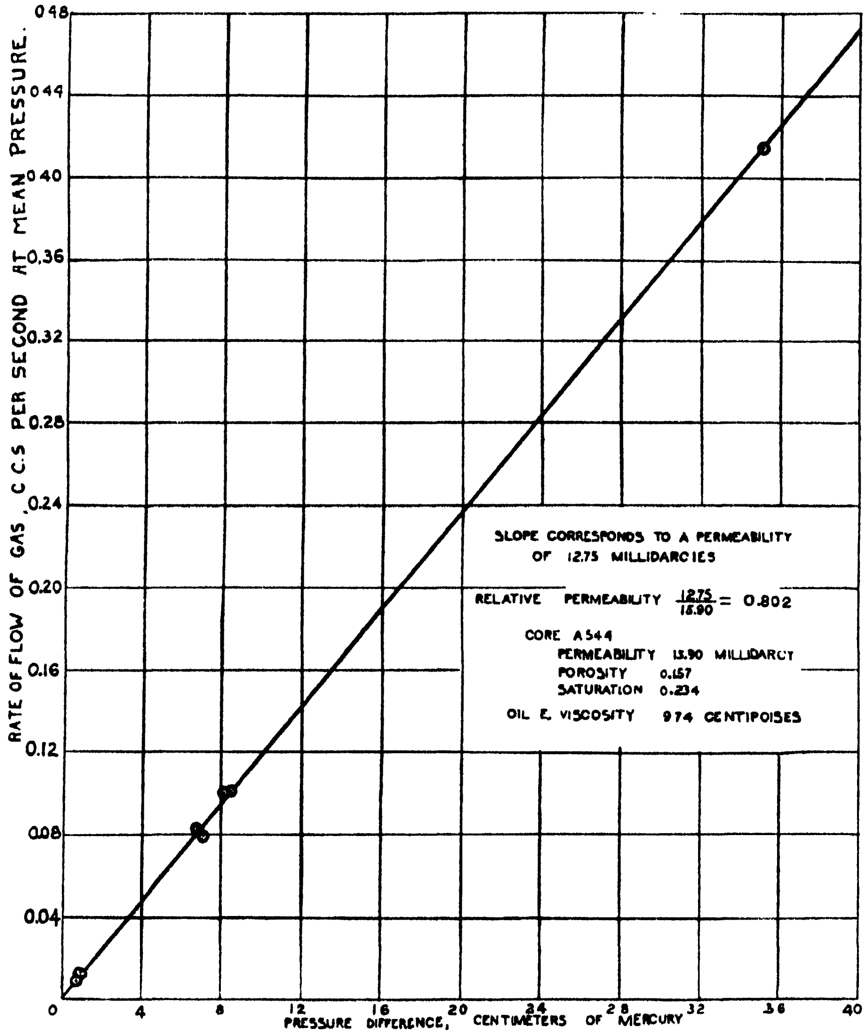

FIG. 6. Data showing how Darcy's law is followed by an oil-bearing sandstone.

An Attempt to Account for Fractional Values of the Velocity Exponent *n*.

Consider the steady flow of a volatile liquid through a sandstone towards a region of lower pressure, as for example, the liquefied hydrocarbons in a gas sand. If it be assumed that the saturation is unity (completely filled void space) at the formation pressure, then as the mixture is moved towards a region of lower pressure the gas will come out of solution in accordance with the pressure-volume relationship for the chosen oil [19, 1936; 20, 1933].

For any back pressure there will be a particular variation of saturation with distance from the well. In this steady state, since the mass velocity is constant, the velocity of gas will increase towards the well as the saturation disappears. The relationship between saturation s and mass velocity of the gas may be written approximately

$$\rho v = C(l-s), \tag{11}$$

where C is a constant involving the ratio of the volume of the gas to the volume of the liquid $(l-s)$ from which it was derived. C also depends on the flow pattern.

This gas is flowing through sandstone in company with the liquid. It is known that in the case of 'dead' liquids the effect upon the pressure gradient is as if the sandstone and liquid were a single porous medium of smaller permeability in accordance with the equation (9). It may not be too far wrong to assume that some such law of variation is valid for the case of a mixture of gas and 'live' or bubbling liquid. The law varies somewhat with type and permeability of the rock. It is not extravagant to suggest that for most reservoir rocks, particularly if the permeability is high, the formula

$$K(s) = K(l-s)^b \tag{12}$$

is adequate for low saturations, say up to 20%, if b is a suitable positive constant around one-half or one-third.

This may best be demonstrated by plotting equation (12) and comparing the plot with the empirical equation (9) for small values of s.

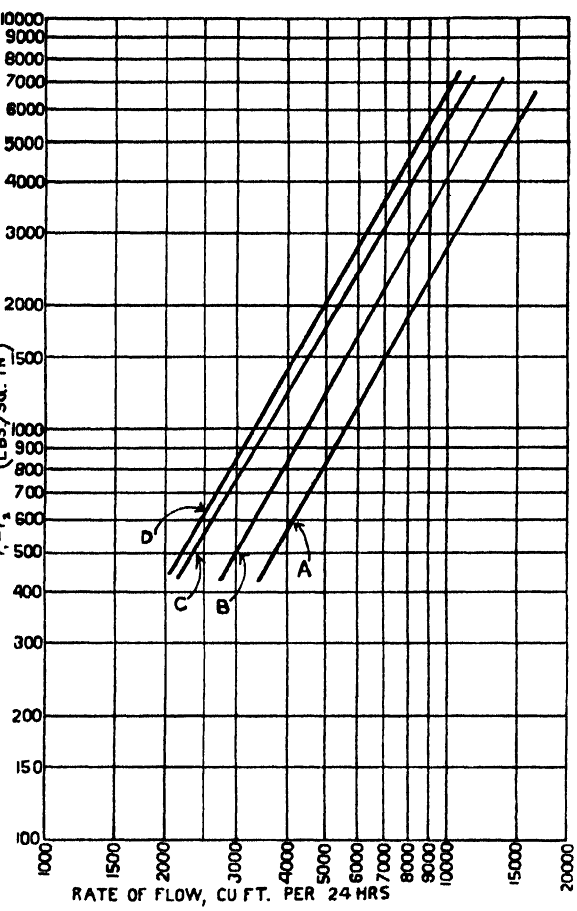

FIG. 7. (Data of Rawlins and Schellhardt. *U.S. Bureau Mines Monograph*, 7, 203 (1935).)

Flow of air through 20–30 separation of river sand wetted with light lubrication oil.

A. Dry sand.
B. After adding 25 cm.³ of light lubricating oil.
C. „ „ 50 „ „ „
D. „ „ 100 „ „ „

The apparatus was so arranged that oil was blown out of the sand during the experiment, so that the saturation is indefinite.

The differential form of the experimentally determined law of flow of gases in porous media, equation (8), may be rewritten,

$$\frac{d}{dx}(P^2) = \frac{Z}{K}(\rho v)^n. \tag{13}$$

Under the conditions of this discussion the mass velocity ρv and the permeability K are expressible as functions of s. Upon substitution from (11) and (12), equation (13) becomes approximately

$$\frac{d}{dx}(P^2) = Zc\,\frac{(l-s)^n}{(l-s)^b} = Zc(l-s)^{n-b}. \tag{14}$$

Upon replacing the expression for mass velocity into (14), (13) becomes

$$\frac{d}{dx}(P^2) = Zc(\rho v)^{n-b}. \tag{15}$$

If the above argument is valid the frequent occurrence of velocity exponents less than one as proved by the data of Rawlins and Schellhardt (Fig. 4) have been accounted for.

Since the lowest possible value of n is unity it may be concluded from Fig. 4 that the largest value of b which occurs commonly in nature is about six-tenths. There are not yet sufficient data to discuss the physical meaning of the constant b from the standpoint of physical structure, but it seems clear that b is associated with that property of a sand which permits it to hold oil in the presence of a gas drive. If b is low the sand can be saturated to a higher degree before any appreciable reduction in permeability occurs; if b is high the presence of a little oil will greatly decrease the permeability.

It may follow that high values of b in an oilfield will imply a low gas factor while low values of b imply less efficiency in the last stages of recovery, since it will be expected that oil which is so distributed that it does not resist the flow of gas will be hard to displace by gas flow.

The data of Fig. 4 were all obtained from gas-wells, but with sufficient experience in correcting for the presence of fluids in the well there is a good chance that similar curves can be obtained in depleted oilfields.

These remarks will not have any practical value unless it is possible to distinguish the turbulence effect, represented by n, from the saturation effect, represented by b, in the velocity exponent $n-b$. However, it will often be possible to estimate what the separate influences are from the production rate and from comparitive experiments made on the dry or partially saturated sand in the laboratory.

It should be emphasized that the above argument is not in any sense complete. There is reason to predict that a more exact statement of the relationship between saturation and gas velocity, and of the relative permeability $K(s)$, will reveal variations in n which will depend on factors important for a better understanding of oil and gas flow.

The Relationship of Permeability Research to Mathematical Analysis of Oil-flow Problems.

The shape factor. In any real problem of flow in nature the calculation of the effect of the shape of the sand is apt to be too difficult to yield readily to the present knowledge of mathematical analysis. As a result of this difficulty only those few cases have been brought under the yoke of common understanding which are so simple in geometry that this shape factor can be handled. Thus the two standard shapes used in calculating the permeability from the flow measurements are the cylindrical sample in which the flow is one-dimensional (generally circular in section but sometimes square) and the radial flow sample, in which the fluid is caused to move along the radii of two concentric cylinders which form the inlet and outlet faces, the top and bottom being ground off as flat planes.

In the first case the differential form of Darcy's law for incompressible fluids, equation (1) above, can be integrated immediately to the form

$$\frac{Q}{t} = \frac{KA(P_1-P_2)}{Z\quad L} \tag{16}$$

A = area in square centimetres of section of cylinder,
L = length of cylinder in centimetres.

Here the shape factor A/L is simple enough to predict by intuition. In the radial flow case dQ/dt must be set inversely proportional to the radius r,

thus, $$\frac{dQ}{dt}\cdot\frac{1}{2\pi r} = \frac{K}{Z}\frac{dP}{dr}, \tag{17}$$

which integrates to the form

$$\frac{Q}{t} = \frac{2\pi K(P_1-P_2)}{Z \log r_1/r_2}. \tag{18}$$

Here the shape factor is

$$\frac{2\pi}{\log r_1/r_2}.$$

In these two cases may be found a geometrical combination which is easy to fabricate in rock (by grinding with an abrasive tube or a flat plane) and which is also easy to handle mathematically.

However, it is easy to see that while these things permit the laboratory measurement of permeability, circular cylinders are a far cry from the geometry of a real secondary recovery oilfield. The more ambitious attempts that have been made to deal with the flow of wells include the following examples:

The above formula (18) for radial flow may be used to calculate the flow of *water* in water-bearing sands [36, 1936] which are uniformly permeable and of uniform thickness by measuring the shut-in pressure at wells which are at distance r_1 and r_2 from a producing well to obtain P_1 and P_2 respectively. A simpler method, which, however, is limited by the accuracy with which a well diameter can be stated, has also been given in the literature [39, 1934]. These methods may not be used directly to deal with oil-wells because the varying saturation of oil, or varying content of gas make it inadvisable to assume uniform permeability to flow of either liquid. There are rare edge-water drive fields in which oil does not release gas in the sand, and in this case the radial flow formula is of course applicable [39, 1934].

In the case of gas-wells which have dry sands the radial-flow formula can be put into the form (39, 1934)

$$\frac{\bar{Q}}{t} = \frac{2\pi K}{Z}\frac{(P_1-P_2)}{\log r_1/r_2} \tag{19}$$

by substituting Boyle's law into (18).

$\bar{Q}$ is the rate of flow reduced to mean pressure $\frac{P_1+P_2}{2}$.

The shape factor $2\pi/\log r_1/r_2$ may be corrected for the exposed bottom of the hole in the case of partially penetrating wells by inserting a correction factor into the formula [39, 1934].

However, it has been shown [28, 1935] that the flow of gas from gas-wells is not generally in accordance with Darcy's law. Instead, one must use the more general form of the law of flow as given in equation (13).

On this basis Botset and Muskat [24, 1931] have derived formulas which may be used to predict the rate of flow in various stages of exhaustion of a gasfield, for any value of n. Recently Muskat [22, 1934] has presented a very complete treatment of compressible fluid flow which includes non-radial flow and transient conditions of flow for homogeneous fluids.

Another very interesting approach to the problem of boundary conditions or shape factor is offered by Moore, Schilthuis, and Hurst [21, 1933] in conjunction with a method for determining the average permeability of a well from field data. In this treatment the boundaries of the medium are the walls of a fully penetrating well and the top and bottom of the sand, while the outer drainage radius is disregarded on the following grounds: If the pressure be changed suddenly on a sand containing a compressible fluid, the instantaneous rate of production of the fluids in the sand near the well will be independent of conditions at a distance from the well. Hence by studying the 'draw down' and 'build up' curves of pressure at the face of the well during a short period, together with the simultaneous oil and gas production and the variation in the casing pressure, it is possible, using certain assumptions, to determine the effective permeability of the sand. It is clear that this cannot be done if adjacent wells are so close that they are affected by the change within the time of the test.

One other possibility of avoiding boundary calculations in permeability measurements that seems to have been neglected by laboratory technicians to date is the very small inlet (or outlet) face in or on a large porous medium of any shape. In this case, if all other significant boundaries be at a distance which is large with respect to the dimension of the inlet, all of the resistance to flow is concentrated around the inlet so that only the geometry of the inlet need be considered. In such a case it is legitimate to speak of the 'flow capacity of the inlet' as a quantity which depends only on the permeability. It should be possible to measure permeabilities, for example, by pressing a 2-in. rubber stopper with a very small central hole against a fractured face of the rock under test. If a fixed suction is then produced at the hole the rate of flow will be dependent only on the permeability of the rock so long as the nearest inlet for air is at a distance greater than the radius of the stopper. Such 'electrode resistance' or 'point resistance' measurements are in common use in electrical practice, and the theory is complete there [15, 1925].

One other group of 'shape factor' problems has received fairly complete treatment at the hands of Muskat and Wyckoff [25, 1933; 38, 1932]. In the case of a sand of uniform thickness bearing a homogeneous gas-free liquid in steady state, viscous flow, the wells may be regarded as point sources and sinks in a logarithmic potential field. The 'shape' of the medium is completely described by the thickness of the sands and the distribution of the wells. In this case these authors have calculated the conductivity and manner of flow of the 'five spot', 'seven spot', 'line drive', and other flow patterns used and proposed for use in water-flood properties. The 'shape factors' so obtained are quite complicated, but the analysis has been checked by the method of electrolytic models [38, 1932] and is without doubt valid under the assumptions.

The Analytical Treatment of Polyphase Flows.

In all of these cases it is necessary to make assumptions which are not permissible for an oilfield which contains mixtures of oil and gas, or oil and water. There are two principal difficulties in such calculations. The first and most important difficulty lies in the fact that the actual fluids are not homogeneous—they are more often immiscible mixtures of oil and gas or oil and water, or all three together.

Thus in the paper by Moore, Schilthuis, and Hurst [21, 1933] a mixture of oil and gas is treated as a single fluid whose compressibility is determined by experiment. There can be no objection to this if there is evidence that the oil and its associated gas move as if they were bound together as a unit. There is reason to believe, however, that this is not true. The fact that the gas-oil ratio of a field changes continually must mean that the gas and oil are not bound together.

The last words of the late Dr. Versluys [35, 1934] on the subject may be quoted to advantage:

'Close to the well, not only a simple depletion occurs, but also part of the oil and gas from outlying regions have to pass. . . . It would appear to be impossible to make any calculations on this subject. . . . The total work . . . cannot be known until production has ceased, because it is impossible to hazard any theory on the way in which the energy from the expanding gas is imparted to the liquid, and how the oil and gas move, so that the consumption of energy through friction is also beyond computation; further calculation is therefore of no value.'

Recent experiments by the author [11, 1936], summarized in equation (10) above, show that the ratio of gas flow to oil flow in the case of dead oil in Bradford sandstone will decrease about tenfold for every 12% increase in saturation. This fact has been determined for all saturations between 20 and 70%. Furthermore, this gas-oil ratio is a function of the pressure gradient [10, 1936]. It seems to vary inversely about as the square of the pressure gradient at 40% saturation.

Hence, even though some resemblance between his conclusions and the facts is observed, Hurst [21, 1933] is not justified, logically, in using in the flow equation

$$\frac{\delta^2\bar{p}}{\delta r^2}+\frac{1}{r}\frac{\delta p}{\delta r}-\frac{c\phi}{\bar{K}}\frac{\delta\bar{p}}{\delta t} \tag{19}$$

$\bar{p}$ density of gas-oil mixture.
r distance from well.
ϕ porosity, fraction.
$\bar{K}$ = permeability cu. ft. per day per sq. ft. per lb. per sq. ft. per ft.

a $\bar{K}$ which lumps together the influence of viscosity of the fluid and the resistance of the rock. Obviously when this oil-gas mixture has expanded from, say, 1% of gas (in which region of saturation the pressure is distributed by movement of the oil) to 30% of gas (in which range the pressure is distributed by the gas) that viscosity which determines the relationship between rate of flow and the pressure gradient will change from the viscosity of oil to the viscosity of gas. Hence $\bar{K}$ as defined is not a constant in fact, and as measured with this theory has no definite meaning.

It is probably true that as a consequence of statement (4) (below equation (10) above) in the *steady state* of flow of oil and gas towards a well, the effective permeability to gas will be reasonably constant in the region near the well, so that a constant such as is implied by the above equation can be defined. However, it is difficult to see how the transient conditions of flow dealt with in the field permeability determination of Moore, Schilthuis, and Hurst [22, 1934] can be treated by this approach.

The discussions of the problems of secondary recovery by water drive [25, 1933; 23, 1934; 38, 1932] are similarly limited by a lack of experimental data on which to base those assumptions which must be made about the permeability of the rock to the respective fluids. Although in the references given these assumptions are clearly stated, they seem to be invalid. Torrey [34, 1933] has published data on the resistance to flow of sandstones which contain oil. These are plotted on Fig. 5 above. These data show, for example, that a mixture of half oil and half water will flow about 3% as fast as pure water. Since a water drive is characterized by a wide transition range at the front of the flood which contains mixtures of oil and water, it is clear that the usual assumptions, according to which the homogeneous fluid permeability is used with a viscosity near the weighted average of the viscosities of the fluids to calculate the flow, are dangerously in error. It is probable that the resistance to flow is much higher in the region of the front of the water-flood and behind it than it is in the unflooded region. These factors will invalidate any calculation which makes direct use of the theory of logarithmic potential.

In particular, Torrey's data on the resistance to flow of water-oil mixtures demand that a greater part of the pressure drop takes place between the inlet water-well and the front of the flood than has been thought possible; the resistance of the oil-gas part of the pattern must be discounted. The flood will therefore take a form more nearly resembling a circle having its centre at the inlet well: the distortion of this circle, which is caused by pressure gradients arising from the neighbouring wells, will be much less than predicted by Muskat [24, 1931], Nowels [26, 1933], or Herold [12, 1928].

It will be impossible to state at present just what is the shape of a water-flood, for we have just enough data to indicate that those assumptions which make the calculation possible are too far wrong. When more data are collected on the resistance to flow of oil through sandstone which contains gas and on the flow of water, oil, and gas mixtures, it may be possible to find methods of calculation which will be serviceable in predicting the relative efficiency of the various water-flood patterns and gas-drive patterns. Until then it will be important to hold firmly in mind that the permeability, as ordinarily understood, is not even an approximate measure of the resistance offered to non-homogeneous fluids by reservoir rock.

Those who wish to make quantitative use of a concept of permeability find themselves in a dilemma the responsibility for which may be laid to the industry as a whole. In the oil-producing business there has never been any adequate support of fundamental research as distinguished from engineering. The problem of keeping a simultaneous record of gas content, oil content, water content, and rate of flow of all these, is so difficult for real sandstone that the ultimate solution of the difficulties set forth above will require dependable support for high-quality research men for a reasonably long period. Nothing like this has been seen until very recently. It is to be hoped that the result of such work, when it is obtained, will be published without delay.

DEFINITIONS OF SYMBOLS

P pressure.
P_m mean pressure $(P_1+P_2)/2$.
P_1 inlet pressure or closed-in reservoir pressure.
P_2 outlet pressure or bottom-hole pressure.
V, V_m, V_1, V_2, volume of gas moved past a section of the rock.
Q volume of fluid moved past a section of the rock.
$\bar{Q}$ volume of fluid moved through the rock reduced to mean pressure $(P_1+P_2)/2$.
t time.
K viscous permeability for single-phase fluid flow [1, 1935].
$\bar{K}$ permeability as defined in reference [21, 1933], cu. ft. per day per sq. ft. per lb. per sq. ft. per ft. referring to a gas-oil mixture.
$K(s)$ ratio of viscous permeability at saturation s to the 'dry' permeability K.
n velocity exponent as defined in equations (6), (8), (13).
m reciprocal of n.
v velocity of flow of gas.
s ratio of liquid volume to total void space (saturation).
A area.
L length.
ρ density of gas.
$\bar{\rho}$ density of oil-gas mixture.
Z viscosity, centipoises.
x length co-ordinate, whose direction is the direction of flow.
r radius of a cylinder, distance from the centre of a well porosity.

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THE MIGRATION OF OIL

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THE commercial supplies of petroleum and natural gas are found normally as impregnations of porous rocks such as sands, dolomites, and limestones. The oil and gas occur in the pores and fissures of these rocks under high pressure, and when the rocks are penetrated during drilling these materials flow towards the well along the channels within these permeable rocks. There can be no doubt that a still larger amount of oil and gas occurs as a more widespread but less concentrated impregnation of the denser rocks, the clays, marls, and limestones surrounding the reservoir rocks. Such rocks are, however, exceedingly impermeable, and there is therefore no commercial method of extraction. It is generally agreed, however, that these denser rocks are, in the main, the media in which the oil originates, and their oil content is therefore not surprising.

So far as the reservoir rocks are concerned few geologists would assert that there is any possibility of oil originating in a sand, though some limestone reservoir rocks may originally have functioned also as source rocks for the petroleum.

While it would be legitimate to consider some oil-pools as having originated *in situ*, the vast majority of fields must have demanded a considerable amount of oil and gas movement and, furthermore, in all cases there must have been a differentiation of oil and gas from water in the sediments. These movements of concentration and segregation are spoken of as the migration of petroleum.

The study of migration begins with the consideration of the factors which govern the first processes of concentration whereby the dispersed oil and gas are gradually shepherded to the reservoir rock. It traces the further movement of the materials within the reservoir, segregating the gas and oil as separate bodies in well-defined zones within the rock mass. It is concerned with all the movements of readjustment in these zones which occur during the passage of geological time as a result of the changes which take place in the rocks around and in the hydrocarbons which have been temporarily imprisoned. Its final aspect is a study of the dispersal of the oil and gas as the processes of denudation permit access to the reservoir, and Nature's forces, previously held in check, give rise to new movements within the reservoir. Then the gas and oil are either moved onwards to new and temporary homes, or they are brought to the earth's surface and dispersed.

There exists in the literature of the subject a great deal of confusion and apparent contradiction due to the use of the term migration in distinctly different senses by different authors. Some visualize the term migration entirely as a process of separation of gas and oil over water within a reservoir rock, whereas others are concerned solely with the processes whereby the oil leaves the source rock and accumulates in the reservoir rock. In order to avoid some of this confusion the author has suggested the use of the terms primary and secondary migration to cover two distinct phases of the process [13, 1933]. It is important to distinguish them because they represent migration under different physical conditions, though it is impossible in many cases to separate the two phases in the final distribution of the oil and gas in the pool.

Primary migration is concerned with the initial process of oil and gas movement whereby the material is moved from the source rock and flows to the reservoir rock. It is essentially a process of rock selection whereby the oil and gas choose a more coarse and porous rock in preference to a fine compact one.

Secondary migration is concerned principally with the fluid movements within the coarser rocks whereby the gas, oil, and water are separated and come to rest in different portions of the reservoir rock. Generally the gas, oil, and water sort themselves out in the reservoir rocks in order of density. The gas occupies the highest part of the reservoir, whilst the water occurs at the base. There is also a certain amount of selection due to coarseness, the water tending to occur in the finer rocks, whereas the oil occurs in the coarser. This effect of pore size sometimes produces anomalous results such as the occurrence of water resting on oil in what appears to be the same sand body. There are, therefore, clearly several influences at work governing the distribution of the gas, oil, and water within the reservoir rock.

Primary Migration

The main problem of primary migration is to explain the enrichment of the sands, dolomites, and limestones with oil and gas at the expense of the more compact source rocks in which the oil is believed to originate.

It might appear at first sight that the problem presented very little difficulty. The oil and gas choose the sands and other reservoir rocks because they are porous. One of the chief difficulties, however, is that the reservoir rocks are surrounded by compact rocks which are themselves impervious, so that it is not easy to see how any movement of oil, gas, or water could have taken place through them. So fundamental is this difficulty that many geologists have, as a consequence, refused to admit extensive migration of this sort and have claimed that the oil must have originated in the compact rocks immediately adjoining the porous reservoir.

It was on this account that Sterry Hunt, as early as 1861, concluded that oil in the Trenton limestone of Canada had a purely local origin. It is, however, argued by others that although the surrounding rocks are compact they are not absolutely impervious and that over long periods of geological time there will be slow movement through the whole rock mass. J. L. Rich [28, 1931] strongly supports this point of view and believes that fluid movement occurs throughout the sedimentary rocks, though of course it is more apparent in the more permeable carrier beds. There is, however, one piece of evidence which makes the assertion of unlimited permeability untenable. It is to be found in the differences in pressure in adjoining sand bodies when they are first penetrated. Were there even only a limited communication between such masses one would expect them to have attained, over long periods of time, an ordered sequence of closely related gas pressures. Whilst it is a general rule that pressures increase with depth, there are so many local anomalies that it is impossible to allow even a limited amount of communication between the sand

bodies showing these anomalies. One must therefore conclude that in the majority of cases the enclosing rocks are in fact impervious.

Causes of Primary Migration.

It is useless to discuss the buoyancy of oil in water and the separation of gas, oil, and water according to their densities within a rock which is itself so compact that any movement whatsoever is extremely doubtful. Clearly, therefore, buoyancy, which is a commonly accredited cause of oil migration, cannot function as a cause of primary migration whatever importance it may have later on within the reservoir rocks themselves.

Of the possible causes of primary oil migration the following may be considered as the most important.

1. Capillarity. The suggestion that oil migration was primarily due to the difference in surface tension of oil and water seems to be ascribable in the first instance to C. W. Washburne [36, 1914], but it has been due largely to the work and writings of A. W. McCoy [18, 1918; 19, 1919] that this theory has gained wide recognition. McCoy uses the term 'replacement theory' for the whole process, and he describes it as a slow process of interchange in which the oil moves to the coarse rocks and the water moves to the fine. The movement is claimed to be due to the fact that the surface tension of water is more than twice that of crude oil, so that the water tends to displace the oil from the finer capillaries. The oil so displaced moves into the rock with the larger pores, thereby enriching the sands with oil at the expense of the finer source rocks.

This theory has gained many adherents, for it gives a simple explanation of one of the dominant characteristics of all oil accumulation—that oil always seeks the coarser rocks. In some oilfield regions, notably Pennsylvania, coarseness appears to be nearly always the major factor, and the oil accumulations in the sand bodies are restricted to the coarser streaks. Numerous experiments have been carried out which appear to support these views, though it may be remarked that the experiments are open to the criticism that they invariably introduce other factors which may possibly be the cause of the movement observed.

It must be remembered that the sands and clays in nature are originally water-wet, so that the oil interspersed through them will exist as globules or masses in the water-wet capillaries. So long as such oil masses lie entirely in the fine or in the coarse zone there can be no driving force acting on them by virtue of surface tension. The oil will assume an external form wherein all the external forces acting on it, buoyancy and surface tension, are in equilibrium. Once this condition is attained surface tension will tend to prevent any change rather than cause further movement. Undoubtedly an oil mass which happens to lie across the interface of a coarse-fine junction will adopt an external form which was related to the capillary conditions in the coarse and the fine portions. It may in doing so retract entirely into the coarse zone, but it can attain equilibrium without doing so. A simple and critical experiment in which all factors save surface tension are eliminated consists in the introduction of oil globules into a converging capillary full of water and placed in a horizontal position [13, 1933]. If this be done, it will be noted that the oil globules assume a rounded but slightly asymmetrical form and then undergo no further movement. There is no tendency for the oil to travel to the wide end of the capillary. Surface tension merely alters the outer form of the globule, and it requires a definite external pressure to produce any further movement. The oil globules resist movement according to the well-known Jamin principle [10, 1928], and no flow can take place in the capillary until the difference in pressure at the ends exceeds the back resistance. In other words, the function of surface tension in the conditions under discussion is to retard rather than to cause movement.

2. Hydraulic Currents. Perhaps the most generally accepted views on the cause of primary migration ascribe the oil movement to the drag effect of water currents within the rocks. There are, however, various hypotheses as to the cause of such currents, and it is essential in discussing fundamentals to inquire how these currents are produced. Three causes of fluid movement are possible: general hydraulic currents due to differences of artesian pressure; the currents due to compaction of sediments; and lastly, the fluid currents due to diastrophism.

Dealing first with the hydraulic currents due to differences of artesian pressure, it is well known that water passes along the more permeable beds for great distances and in doing so it will tend to flush any oil met *en route* in the direction of its flow. This is a common means of oil dispersal whereby oil accumulations are sometimes flushed to the surface and lost. But the principle as applied to primary migration must involve artesian flow in the fine-grained and compact rocks, and it is very doubtful if such movements are possible once these rocks have reached this compacted condition. Some authorities assert that fluid movement takes place through all the sedimentary rocks, the more permeable beds allowing easy flow along their bedding-planes, and the compact rocks allowing only a very slow movement. If this be true, we have in the general water movement a sufficient explanation of migration. But while no one would doubt the effect of hydraulic currents in the permeable beds, there is no good evidence for a general water flow through all rocks. The variations in oil and gas pressure in neighbouring sands support the belief that once a clay has been thoroughly compacted no appreciable fluid movement is possible through it.

One of the first supporters of the theory of oil flushing by hydraulic currents was M. J. Munn [25, 1909]. Although he was not so much concerned with the causes of these currents as with their action in sweeping the oil into suitable reservoirs, yet it is fairly clear that Munn considered that much of this water movement was associated with compaction. The water was squeezed out of the sediments by the increasing load, and in its escape it used the sand beds as convenient avenues of movement. These ideas belong properly to the following section. Munn, however, was mainly concerned with oil and water movement within the porous rocks, and his views have a more important bearing on secondary rather than primary migration.

3. Compaction Currents. When a clay, marl, or argillaceous limestone is first deposited it is primarily a clastic or organic medium containing a large volume of interstitial water. The percentage of this water depends on the type of clay, but it is by no means unusual for such a sediment to contain 60 to 80% of water by volume. Such a material has solid properties in spite of its large water content, it resists deformation and compression within the limits of its own strength, but above these limits water is gradually expressed and the sediment diminishes in volume. Continuous sedimentation therefore, inasmuch as it increases the pressure on the underlying sediments, causes a slow outflow of fluid and a gradual diminution of bulk volume in all the argillaceous or marly sediments. This process of

compression is called compaction, and it involves the outflow from the sediments of a volume of water several times greater than the final volume of the sediment [35, 1932]. Here is a considerable movement of fluid which must take place in all such sediments before they can become rocks, and it is legitimate to consider that this movement may have a profound influence on any other mobile materials such as oil and gas which may occur in the sediments at this early stage in their history. The fact that many of our oil reservoir rocks are completely surrounded by impervious sediments, and yet that we are forced to conclude that the oil must have been able to pass through these rocks at some stage in their history, can have only one logical explanation, that the oil migrated before these rocks were thoroughly compressed and impervious. Here, then, the process of oil migration is linked up with a universal process of fluid movement which takes place in all the argillaceous strata in the early stages of their formation.

It is important to consider a little further how the water flows out from the compacting clays. Obviously it will flow along the paths of least resistance. Much of it will go back directly to the overlying water sheet, particularly in the upper layers of the sediment. Some of it may pass into the permeable rocks which form the foundations of the sea floor and find its way by devious paths back to the sea again. Most of it, however, must pass through the bulk of sediments in a general upward direction, but selecting in its passage the lines of least resistance, i.e. the most permeable rocks. Thus the sand bodies or other permeable rocks become the main channels for the compacting fluids and tend to collect the fluid currents from the surrounding clay masses and concentrate them into a single channel of outflow at the points of minimum back pressure in the sand. This tendency is of the greatest importance, for it makes each sand body into a channel of fluid movement and ensures that all the components of the fluid current make use of the sand bodies in the phase of compaction.

Experimental evidence shows that in such a compacting mass of clays any oil or gas present in the clay medium is squeezed out with the water and tends to follow the general direction of the current. In so doing the flow of gas, oil, and water forms a system or network of channels in the clays and a more simplified type of flow in the sands.

4. Filtration. If attention be focused for the time being on the fluids passing into and out of the sand bodies, it is necessary to consider for a moment the physical processes involved at the interfaces of the sands and clays. Each sand body is a highly permeable receptacle with relatively large pore spaces surrounded by a mass of fine mud in which the capillary interspaces are much smaller in diameter. Both media are water-wet, and the movement of water across the clay-sand boundary is subject to no other factor than the relative permeability of the two media. When gas or oil flows out of the clay mass to the sand interface it passes readily from the fine to the coarse capillaries, for there is no physical barrier to such movement. When, however, the reverse movement is involved, i.e. a flow of oil and gas out of the sand body into the clay medium, the latter being water-wet will not allow the oil and gas to enter the fine capillaries unless or until a sufficient pressure is built up at the interface to overcome the surface-tensional forces at the entrance to these fine capillaries [13, 1933]. The process is analogous to the condition of a fine gauze filter which when wet with water will hold back oil, and when wet with oil will hold back water. It is not primarily a function of the relative surface tension of the two fluids, but is a result of the extra energy necessary to force a liquid into fine capillaries occupied by another liquid with which it is immiscible [34, 1930]. The process involves a large increase in the surface area of the secondary or penetrating fluid, and before it can enter additional pressure must be exerted at the point of entry. It can be shown experimentally that for oil to enter a water-wet capillary or for water to enter an oil-wet capillary a considerable pressure is necessary, and this pressure increases as the capillary diminishes in diameter.

As indicated above, the fluid movement from a sand to a clay is similar in physical terms to the movement from a coarse to a fine capillary. Hence, when the compacting fluids containing oil and gas reach the boundary of the sand bodies the water passes onwards into the clays without difficulty, but the oil and gas are filtered out of the fluid stream at the coarse to fine interface and remain locked in the sand body. By this means a fluid stream with only a small percentage of oil and gas can enrich a sand through which it passes until it becomes an oil and gas sand. There must obviously be a limit to such a process, and the limit is reached when an excess pressure is built up within the sand body sufficient to overcome the surface-tensional forces at the interface. This would certainly arise if a sand became filled with oil or gas, and the excess of the latter would then pass on to be trapped in other sand bodies along the route of the outflowing compaction liquids.

According to this view each sand body acts as a filter for oil or gas because its envelope of clay is water-wet. Furthermore, within the sand bodies themselves each coarser streak selectively retains the oil and gas, the process of filtration always taking place at the point of egress from the coarse to the fine rock. It must be emphasized that this selection of the coarser rock, although dependent on immiscibility and surface tension, is not due to the fact that water has the higher surface tension. If the media were originally oil-wet, the water, not the oil, would be trapped in the coarser rocks, for it is always the secondary fluid which tends to be retained in the coarser medium irrespective of the relative surface tensions of the primary and secondary fluids.

As the process of compaction proceeds the clays lose their fluids and become more compact. Their permeability is thus reduced and the egress of the fluids is hindered. Thus the fluid currents are gradually damped down in their intensity by the gradual increase in density of the clay media. No data are yet available to decide whether the currents cease for lack of available fluids or whether the clays themselves become so dense and impervious that further movement of fluid becomes negligible, but it seems probable that the latter is the more normal course. Further drying of the clays is probably due mainly to mineralogical changes within the clay mass involving the absorption of water by the clay minerals.

The oil and gas trapped in the sand bodies are associated also with water which fills the remaining pores. There may still be some local fluid movement into the sand body after the general flow of the compaction currents has ceased, and this will involve the building up of excess pressures within the sand, but at this stage the covering clays over the sand are so dense that loss of oil due to these excess pressures is impossible.

Until this stage is reached all the neighbouring sand bodies are in direct or indirect communication, and the pressures are controlled by the weight and strength of

the compacting medium. Hence the pressures in the sand bodies will be a function of their depth of burial. Once, however, the clay media become impervious the intercommunication ceases and the pressures in individual sand bodies may be affected by factors peculiar to themselves. A sand highly charged with gas would be peculiarly sensitive to temperature changes and might build up abnormally high pressures merely by increase in the earth temperature, so long as the clay envelope was sufficiently strong and impervious to prevent loss of gas or liquid from the sand.

5. Diastrophism. The fluid currents in the phase of compaction are primarily due to the accumulating weight of sediments. But compression may arise from other causes, in particular the stresses within the earth's crust, such as are associated with folding [6, 1916; 33, 1927–8]. Sometimes these conditions occur very soon after sedimentation, and in such cases it is obvious that the stresses will produce additional squeezing of the sediments and accelerate the flow of the compaction fluids. In most cases, however, we may assume that diastrophism succeeds the early phases of compaction, and its effect will therefore only be noted in the later history of the sediments.

One additional aspect of the effects of lateral pressure needs a passing comment here, though it will be dealt with more fully at a later stage. Lateral pressure compresses the clayey sediments and renders them more impervious as a whole, but if carried to the stage at which disruption occurs, the rocks become fissured and fractured. These new features confer a certain amount of induced permeability on the formation, and if they occur within the clay series its impervious condition may be destroyed and further fluid movement out of the sand bodies may take place. Tensional stresses are particularly prone to produce such effects, and the local conditions of tension that may occur on the zone of curvature on an anticline often result in accentuated movement of the gas and fluids through the zone of induced fractures.

The driving force in these fluid movements may be primarily the gas and oil pressures, but diastrophism has opened the door to such movements by the creation of induced permeability, and in some cases the lateral pressures themselves may have caused some of the fluid outflow.

Secondary Migration

It has been emphasized already that there are two aspects of migration. First, the original enrichment of the reservoir rock with oil and gas, and secondly the segregation of this material into certain restricted zones within this rock. Sometimes these two stages of movement are merged into one, but more commonly, and particularly in extensive reservoir rocks, the internal adjustments are very considerable.

Two major features are common to all cases of secondary migration. First, the gas and oil seek the highest possible position within the porous rock, the gas being above the oil or in solution. Secondly, the coarser sections of the reservoir rock tend to retain the oil, whereas the water lies in the finer sections. It is difficult to say which of these two principles is the dominant one, for their relative importance varies with the conditions.

Flotation.

The fact that the gas, oil, and water are generally separated into three layers in the order of their densities seems to find an obvious explanation in the principle of flotation. This has been accepted almost without question as the fundamental principle of oil accumulation and was the basis of the anticlinal theory as promulgated by Sterry Hunt [12, 1861]. Before, however, the theory is accepted it is necessary to examine more closely the conditions of the fluids and gas in the reservoir rock. The latter is not an open receptacle, but is a solid medium full of minute capillaries. Within these minute pores the fluids are obviously confined much more effectively than they would be in an open receptacle and their power of free circulation is severely limited by their being in the capillaries. In the case of mixed fluids of different densities the gravitational forces will tend to separate the lighter fluids into the upper zones, but unless these forces are sufficient to overcome the forces of surface tension inhibiting movement in the capillaries, it is difficult to see how flotation can occur. A drop of oil in a water-saturated sand would exist as an irregularly shaped mass bounded by numerous water-oil interfaces in the capillaries. To allow any movement of this mass of oil the oil-water interfaces would have to be distorted and then set in motion. To achieve this a sufficient pressure would have to be exerted to overcome the forces of surface tension at these interfaces, and these forces would obviously be greater the finer the capillaries. It is therefore not at all certain from first principles that gas, oil, and water will separate out by flotation in the pores of a rock, and it is clear that the separation will depend on certain limiting conditions, the relative importance of surface tension and buoyancy. When these principles are examined experimentally it is found that in normal sands the effect of gravitation is too small to cause oil to separate over water and form an upper layer [8, 1921]. An effective separation will occur only when the coarseness of the reservoir rock approaches that of grit, but normal oil sands are too fine for such separation.

It might be argued that oil separation would be induced by flotation provided the oil masses were originally large enough [2, 1930; 36, 1914]. The upward thrust of buoyancy would increase as the cube of the diameter of the oil masses, whereas the resistance to movement would be proportional to the square of the diameter. This argument is, however, invalid, for before these masses can become large there must be sufficient movement to allow them to grow by combination.

In addition to the evidence of experimental investigations there are several instances in oil-pools where the original oil-water surfaces have such a marked inclination that it is difficult to explain on any principle of gravitational separation how such inclined surfaces could be maintained.

On the other hand, there are some oil-pools where a clear case can be made out for static separation of oil and gas over water. These three materials are found in the first instance in separate layers with horizontal planes of demarcation. When these conditions are upset by uneven drilling and production, the readjustments set up obey the normal flotation principles. In other pools it is found that the oil and water layers are interbedded, and the distribution of the oil and water is altogether irregular.

It is therefore considered that, whereas in the coarser reservoir rocks such as grits, dolomites, and fractured limestones the principle of buoyancy is a complete explanation of the internal segregation of gas, oil, and water, this explanation is inapplicable to the large proportion of normal oil sands where the capillary interspaces are too fine to allow buoyancy to overcome the resistance offered by surface tension.

Buoyancy due to Gas.

Claims have been made that whereas oil and water will not separate under normal conditions, the presence of gas enables such separation to take place. There is considerable experimental evidence which seems to support this view, mostly based on the introduction of gas into an oil-water mixture in a sand [31, 1920]. Such experiments show a marked separation of oil and gas above the water, but it must be realized that the conditions involving the introduction of gas cannot be achieved without altering the conditions of pressure in the sand and thus causing fluid movement, and, as will be seen later, it is generally admitted that in moving conditions complete separation of oil and water is possible without the help of gas. While, therefore, it is clear that in a flowing stream of water, oil, and gas, the gas aids the separation of the oil, it is not by any means certain that oil and gas lying interspersed in the pores of a water sand will segregate upwards under their own buoyancy unless the pores are large enough to allow buoyancy to overcome surface tension. It seems probable that although buoyancy is a stronger factor in a composite oil and gas body it is insufficient to cause separation in fine sands.

Hydraulic Currents.

Whilst it is extremely doubtful whether oil interspersed in a water sand will separate under static conditions, there can be no doubt that under moving conditions a complete separation is possible. Johnson [14, 1915] was one of the first to draw attention to the importance of moving conditions, and many authors have reiterated the same truth. The essential difference between moving and static conditions lies in the fact that in a flowing stream there is a definite pressure gradient in the fluid involving the traction of each oil mass by the movement in the water around it. The two can move together. During this movement there is a difference of pressure on two sides of any oil mass, causing it to retract from the capillaries on the high-pressure side and to advance into the capillaries on the low-pressure side, i.e. in the general direction of movement. If the advance continues, lobes of oil will pass forward between the grains of sand, and such lobes when free, i.e. in the broader interspaces, always tend to move upwards. Thus there is a preferential selection of the upward capillaries in the forward movement. This means that the separation of the oil is a function of the length of journey and only becomes complete after a considerable advance, a point which is supported by experimental evidence. It must also be noted that this upward separation of oil and gas from moving water is also affected by the coarseness of the sand in which the movement takes place. Where there are sudden changes in coarseness involving a fine sand overlying a coarse one, the coarse to fine interface acts as a barrier to upward oil movement and the oil is held back in the coarser strata [13, 1933]. Where, on the other hand, a coarse sand overlies a fine one, no such obstruction takes place and the oil moves upwards into the coarse sand, only to be checked where the latter is itself covered by a finer grained medium. As a result, therefore, of continuous forward movement through a large sand body containing coarse lenses, the latter filter out and retain the oil to become a series of oil-impregnated coarse sand lenses in a fine water-saturated sand. Such conditions can be claimed to occur in many oilfields, and in the earliest days of the Pennsylvanian oilfield development the term 'pay streak' was largely used for these coarser strata.

In such forward movement, so long as there is no change in coarseness within the rock, the invariable rule is that oil chooses the more upward of two alternative paths, so that where the sand is thick and of even grain size the oil tends to become the upper layer. Where the sand is horizontal this layer will be evenly distributed, but where, on the other hand, the sand is tilted or warped, the oil layer will gather in the higher zones, that is, the anticlines, while the synclines or troughs will tend to lose their oil and to become entirely water-bearing. Where the sand bodies are merely lenses the gas and oil will tend to accumulate in the upper edge of the lens, where the screening effect of the coarse to fine interface will tend to retain them in preference to water. The water flows onwards into the surrounding clays until compaction has rendered all movement impossible owing to the diminished permeability of the latter. Some authors deny that the condition of complete impermeability is ever attained. Rich considers that a certain amount of water movement occurs in all rocks and that this hydraulic sheet is continually moving. Certain of the rock types being more permeable act as the main carrier beds [28, 1931], and in these the main features of lateral oil migration take place. They are Nature's highways for oil migration. In these beds the oil and gas are flushed along by the water currents and ultimately trapped by barriers to their upward and forward movement. Such traps as terraces, faults, monoclinal domes, &c., on otherwise structureless sand sheets tend to strain out the oil from the general fluid current and become the commercial oil-pools. Whilst there is no unanimity on this occurrence of widespread lateral migration, it is none the less true that for many decades new oil-pools have been sought and discovered by the application of its tenets. As instances of such discoveries we may refer to the Cushing Pool where it was claimed by C. Beall that the whole structure had been impregnated with oil and gas by currents from the south-west. Another instance of such trapping is the East Texas field, where the wedging of the sand appears to have been the main cause of the formation of the oil-pool.

These fluid currents within the sand lenses are not always ascribed to the same factors. To many the dominant influence is attributable to the same fluid movement which causes primary migration, i.e. the compaction currents. On this reasoning the movements of primary and secondary migration are all part of one general process, the one leading inevitably to the other, and in its simplest form, the filling of a sand lens with oil, there is no necessity to separate the two processes. To others the compaction fluids are of less importance, and stress is laid on other important water movements in the permeable rocks throughout their history. Such movements may cause concentration of oil, or they may lead to dispersal of oil, according to the direction and strength of the movement.

Capillarity.

In the discussion of the possible causes of oil segregation in reservoir rocks we have already considered static buoyancy, the vehicular action of gas, and the effects of moving currents of water due to many and various causes. A fourth alternative explanation has already been considered under primary migration, i.e. the action of capillarity. Obviously, if the oil is forced into the coarser of two media because it has the lesser surface tension, it ought to occupy the coarser of two sands in contact, or lie in the coarser parts of a sand lens which is variable in grain size. The explanation fits so readily with the known facts that it

is excusable that it has attained such currency. It has, however, been pointed out above that the effect of surface tension as a whole is to prevent rather than to produce movement, and where oil-water mixtures are left in a static condition no internal adjustments take place. One of the fundamental weaknesses of almost all experiments on the effect of capillarity on oil movement is that the media used are not fully compacted and the systems are therefore unbalanced. If left to themselves, they will gradually compact, and this lack of equilibrium inevitably leads to an expulsion of oil and its interchange with the water of the neighbouring sands. It is exceedingly difficult to eliminate extraneous influences if experiments to show the effect of surface tension are carried out with mixed materials without very careful supervision of all the physical conditions. When a simple and critical experiment is carried out such as the introduction of oil drops into a converging capillary saturated with water, no movement of any kind is noted once the oil has been introduced. If capillarity were a driving force, these simple and favourable conditions for its exertion would result in the water driving the oil into the wider end of the capillary.

Adsorption.

It is asserted by some authorities that the chemical and physical nature of the constituents of reservoir rocks has an important bearing on oil migration. Certain media, in particular some of the calcareous rocks, have important adsorptive effects on oils, effects which are selective in their nature and which would automatically lead to the retention of certain parts of a crude oil during its passage through them. Clark [4, 1934] goes so far as to say that he is satisfied that no important oil movement had taken place through the limestones he has examined because of the lack of adsorbed asphalts within them. It must be remembered, however, that chemical experiments on absorption are usually carried out on the carefully prepared dry rock powder, whereas the movement of oil through these media takes place with a film of water over the grains of rock material, a very different condition. It can be shown experimentally that wet limestone or sand has practically no absorptive effect, and that even highly adsorptive earths have their adsorptive powers greatly reduced by the presence of small amounts of water.

The effects of water containing dissolved salts on the physical nature of the oil during migration have yet to be studied. There is no doubt that migration under certain conditions does involve changes in the character of the oils, but many of these changes seem to be due to the effect of physical influences such as differential filtration. Thus, for instance, in the ozokerite deposits of Boryslaw it seems clear that the wax found as veins in the shattered clays has been filtered out of the migrating oil and retained in the clays. Somewhat similar filtration effects may explain some of the thick veins of solid bitumens which have occasionally been exploited commercially.

Reservoir Pressure Changes.

It is obvious that changes in the internal pressure conditions in the water, oil, and gas mixtures will inevitably cause readjustments and some internal movement. Any factors, therefore, which alter the conditions of pressure in the reservoir must influence the course of migration.

Before discussing these factors it is important to note that the gases associated with petroleum are highly soluble in the latter and that the total volume therefore of the oil plus gas depends very materially on the quantity of gas which is in solution. At high pressures and low temperatures the whole of a given quantity of gas and oil may exist merely as a liquid with the gas in solution. Whereas at high temperatures and low pressures much of this gas may come out of solution and the total volume of oil and gas will be greatly increased. The changes in total volume thus produced by variations in temperature and pressure will lead to expansion or contraction of the oil and gas zone of a pool where the water table is free to move. This is seen in the contraction of many oil- and gasfields and the rise in edge-water conditions as production reduces the pressure within the field. On the other hand, in many sand lenses the total volume of the reservoir is limited and there is no excess water available, so that the oil-water surface remains stationary, and the space occupied by oil and gas therefore remains constant. The changes noted in such cases are limited to the gas pressures.

The natural causes of alterations in the pressure within an oil-pool after it has once been formed are:

(*a*) Changes in temperature due to increased sedimentation—causing a rise in temperature—or erosion of overlying sediments—causing a drop in temperature.
(*b*) Increase in pressure due to increase of load by sedimentation, or the reverse effect by erosion.
(*c*) The partial escape of some of the imprisoned material, particularly the gas, by the formation of permeable channels to the surface.
(*d*) Chemical changes of the gas and oil by polymerization, cracking, or other processes of chemical alteration.

All the foregoing factors have considerable influence on oil-pools in the passage of geological time, and so strong are the tendencies towards dispersal that one of the fundamental requirements for the retention of pools through long geological periods is protection from these dispersing influences, i.e. from the migratory nature of oil and gas. Indeed, it may be argued that this feature more than any other has limited the occurrence of oil- and gas-pools of great geological age to such regions as have afforded exceptional protection from oil dispersal. In these favoured areas the strata are either very little disturbed or they are covered with a mantle of some plastic impermeable material such as salt or clay. The oilfields in regions of highly disturbed structures are almost entirely confined to the Upper Mesozoic and the Tertiary, a tribute to the migratory powers of oil and gas where the rock structures are not sufficiently tight to eliminate transformational migration. In this respect it may also be pointed out that the oilfields which show the most spectacular seepages are largely confined to these same young formations, and in so far as an oil seepage indicates active oil migration, this association shows clearly how much the effects of diastrophism in disturbing the strata and opening up channels of movement lead inevitably to the dispersal of oil and gas [38, 1885]. The processes of sedimentary vulcanism, described elsewhere in this volume, are one of the extreme effects of the migratory powers of gas and oil and are conclusive proof of a process of migration which is so far-reaching as to produce rock types and structures of its own.

Lastly, we may turn to the question of the relationships between the problems of migration and those of oil accumulation. In so far as every oil-pool is considered to be the result of migration which has segregated a dispersed fluid into a commercial oil-pool, it may be asserted that

an oil accumulation owes its existence entirely to the processes of migration. All geologists, however, are not agreed on this point. There is a minority school of thought which considers that oil-pools are essentially of local origin and that the source material either is present within the reservoir rock, and therefore there has been no migration, or it occurs in the fine sediment immediately adjoining the reservoir rock so that the migration is limited to the short passage across the intervening space. To such geologists extensive lateral migration is unacceptable, and in the case of limited sand bodies their attitude has considerable grounds for support.

On the other hand, the bulk of geological evidence points to a considerable amount of migration, both lateral and transformational, and while it is probable that in the main most of this migration was upwards, it may not have been so in all cases. Fluid movements tend to be towards the zones of least pressure, but they choose the paths of least resistance and in exceptional circumstances take a downward rather than an upward course.

In the view of those who support extensive lateral migration, an oil accumulation is merely a mass of oil which has been trapped or segregated from the general fluid movement. It represents a mass brought to a standstill by some inhibiting influence, just as a log raft may be produced by an eddy or obstruction in a river. This analogy, like all analogies, must not be pressed too far, but it depicts the accumulation as but one link in a chain of events which begins with the alteration of organic matter to oil and ends, so far as we can tell, with the dispersal of the oil by erosion. The history of the changes may occupy a long period of geological time, and throughout much of this period the oil and gas may be stationary, but the forces are only in abeyance, and whether it be for the purposes of concentration or dispersal they are the same and lie within the province of a complete study of migration.

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SECTION 6

NATURAL ACCUMULATIONS OF PETROLEUM

AN INTRODUCTION TO THE PRINCIPLES OF THE ACCUMULATION OF PETROLEUM

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An oil-pool consists of a zone of porous or fissured rock saturated with petroleum in which the permeability of the rock mass is sufficient to allow the economic extraction of the liquid impregnation. The oil is usually accompanied by gas and is under considerable pressure. It has been maintained in such a condition by an impervious envelope such as clay or water-saturated rock. As oil and gas are lighter than water there is a general tendency for them to occur on the top of the water-saturated sections of the porous rocks, a condition which prevents their loss from the base of the accumulation. In most instances dispersal of gas and oil tends to take place in an upward direction, so that protection from such action is the most important requirement in an oil-pool. This may be effected in many ways, but is usually achieved by a complete cover of impervious rock, called the cap-rock.

Any geological structure which provides adequate porosity suitably protected by an impervious seal may become an oil-pool, provided it is in contact with a source of petroleum. It is therefore obvious that there must be many geological structures which are favourable for oil accumulation.

Almost as soon as the first commercial oil-wells were drilled in the United States of America, speculation was aroused as to the geological conditions which governed the occurrence of the oil and gas. In 1861 the anticlinal theory was advocated independently by T. Sterry Hunt [2] and E. B. Andrews [1], though it is interesting to note that their conceptions were fundamentally different. The ideas of Sterry Hunt conform in principle to the generally accepted theory that the anticline provides a favourable oil structure because oil and gas float to the highest position they can attain in a water-saturated rock. Andrews, on the other hand, considered that the oil occurrences on anticlines were associated with the secondary fissuring which tends to follow the crests. This fissuring produced zones in which fluid movement could take place, and the oil and gas took advantage of such conditions. There can be little doubt that of these two conceptions the former has obtained a wider application and in its modern form the anticlinal theory is largely built up on Sterry Hunt's original ideas. It is, however, interesting to note that there are some cases of oil-pools which are much affected by zones of fissuring, and though Andrews' theory has been discarded, it has a considerable application in limestone reservoirs.

From these early ideas the geological theories of oil accumulation grew in complexity as oil discoveries ranged into new areas where the geological conditions were different. It is interesting to note that the anticlinal theory is not obviously applicable either in Pennsylvania or in Ohio where it was originally applied, and for many years it was strenuously opposed in that area by Lesley and others. However, in the year 1885 I. C. White [4] reviewed and elaborated the theory, and since that period it has received general recognition.

It was soon recognized that other structures besides anticlines were favourable for oil accumulation, and among these the structural terrace was advocated by Edward Orton [3, 1888] as being of considerable importance in areas of gentle dip. There has been a tendency of recent years to doubt whether such structural terraces are of any significance in the concentration of oil, but whether this be so or not, there was one good service which Orton rendered to geologists in the suggestion that oil accumulations were associated with the movement of water and were not merely examples of static separation. The same emphasis on the importance of water currents is discernible in all the writings of Munn and Griswold, and laid the foundation of a more dynamic theory of oil accumulation in which oil was swept into its position by moving water and held in position by the water table.

Such ideas were applied extensively in the search for new oil-pools in the Mid-Continent during the first two decades of the present century, and zones of arrested oil migration were sought on the terraces, monoclinal noses and ravines, and monoclinal domes of the great prairie plains monocline of Kansas and Oklahoma. Any important anomaly in an otherwise uniformly dipping series was considered worthy of drilling, and many oil-pools were discovered on such principles.

The underlying principles governing this search were the application of the idea that an oil-pool represented a phase of arrested migration along a porous rock. The oil and gas had been caught in the structure just as driftwood might accumulate in the back eddy of a river, and the whole technique of oil discovery in such regions of gentle monoclinal dip developed on the lines of searching for and drilling on such abnormalities in the general structure. Faults, too, became a recognized cause of oil arrest, but it was not so much in the Palaeozoic regions of the Mid-Continent as in the Cretaceous monocline of East Texas that the incidence of faulting was first recognized as a dominant influence in the formation of oil-pools. There, in what has been called the Balcones Fault region, the trapping effects of faults were so clearly displayed that there could be no doubt of their importance. The fault in this case was recognized as having created a trap structure by breaking the continuity of the porous bed and plastering its truncated edge with a down-faulted segment of impervious material.

Meanwhile in other areas geological opinion was developing independently along other lines. The structural problems were different, and the oil-pools' relations to the geology were therefore also different. Among the Tertiary fields which followed the main lines of folding there was never any doubt as to the incidence of the anticline; indeed, geologists tended to lose sight of the fact that other conditions besides anticlines could be responsible for oil-traps. The importance of faulting in fold structures was, however, so plain that it demanded recognition, and normal faults, reversed faults, and thrusts were shown to have had a marked influence on the storage of petroleum. One feature which ought to have been obvious merely from a consideration of first principles took a long time to gain

its share of recognition. This was the importance of lenticularity in all types of geological structures as a qualifying influence which limited the application of all other structural theories. This is perhaps seen best in the case of the anticline, where it is now recognized that in regions where the size of the sand bodies is relatively small compared with the size of the folds, the truth of the anticlinal theory becomes limited to the statement that it is the upper part of each sand lens, i.e. the part nearest to the anticlinal crest, which becomes the oil-bearing sector. In such regions the oil-pools may be developed so far down into the synclines that it becomes invidious to speak of the pools as anticlinal. Faulting and lenticularity play an exceedingly important part in fold fields, and many a segment in a typical anticlinal pool owes its importance to these features rather than to the folding.

In the region of the Gulf States and in Germany an essentially different type of oil-pool structure was discovered in the areas occupied by salt-domes. Here the oil was found associated with plugs of salt. It accumulated over the salt-domes or in the highly disturbed strata on their flanks, and a new technique of oil discovery, coupled later on with geophysical investigations, was developed in such areas.

In the meantime, as the more obvious structural zones were drilled up and our knowledge of the structure of oil-pools became more complete, it was realized that some of the earlier structural theories of some of the oil-pools required modification. Foremost among these was the discovery that many of the so-called monoclinal fold fields of the Mid-Continent were probably examples of sedimentation and compaction around buried ridges, and such unconformable conditions began to assume a greater importance in theories of the development of oil-pools. The incidence of such pools as Midway-Sunset had been noted, but their significance had not been stressed until the discovery of the large number of buried structures in the Mid-Continent, and finally the accidental but highly significant discovery of the East Texas pool drew attention again to the importance of unconformities. There is little doubt that the fruitfulness of such ideas has not yet been fully exploited, and oil discovery so far as the geologist is concerned is becoming more and more not merely a study of structure, but a complete study of the whole geological history of an area, a discussion of the phases of sedimentation, and the breaks in such episodes. These take their place with the effects of folding and faulting in the trapping of the oil and gas. In other words, an oil-pool is recognized as an organic whole which has been brought into being by one suite of conditions and preserved by another.

This recognition of the fundamental complexity of the history of most oil-pools and of the many independent features which have had a part in their development, makes it difficult and sometimes even grotesque to label particular pools as being due to single structural causes. Furthermore, a classification of oil-pool structures becomes a meaningless catalogue of all types of structures, for in actual fact oil-pools have been discovered in practically all types, though it is true not with equal frequency. Anticlines, faults, unconformities, the development of induced fissuring, &c., all play their parts, and often their influences are so intermingled that in some pools it is difficult to choose the dominant cause of the accumulation.

In these circumstances it is far better not to attempt an artificial classification of oil-pools, but to consider the broad effects of particular regional types of structural conditions on the formation of oil-pools. In this way the behaviour of oil and gas in different regional structures can be studied and the factors which lead to their arrest in particular areas can be carefully weighed.

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THE POROSITY OF RESERVOIR ROCKS

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In order that a rock may be an effective reservoir two conditions must be satisfied: it must be porous and it must be permeable. Porosity implies the presence of void space within the rock, whilst permeability connotes the ability of the rock to permit passage of fluid through it. The two terms are therefore not synonymous. A permeable rock must be to some extent porous, but a porous rock need not be permeable. As an illustration two cases may be cited, that of pumice and that of a loose, unconsolidated sand. Pumice is very porous, but its pores are isolated one from another and therefore it is impermeable. A loose sand, on the other hand, is also very porous, but there is free communication from pore to pore, and therefore it is very permeable. The permeability of reservoir rocks is dealt with elsewhere in this volume (G. L. Hassler, pp. 198 207), and only those factors relating to the porosity of a rock will be considered here.

The porosity of a reservoir rock is defined as the relative volume of void space in the rock and is usually expressed in the form of a percentage. Its significance lies in the fact that it is a measure of the volume of fluid which may be stored within the rock. The study of porosity involves an examination of the types and extent of the voids, and two distinct measurements are possible—that of the relative volume of the total void space in the rock and that of the relative volume of only those voids which are in intercommunication throughout the rock. The first measurement is termed the total or bulk porosity of the rock, and the second is termed the effective porosity. When dealing with reservoir conditions it is the effective porosity which is significant.

Petroleum reservoir rocks are, with few exceptions, sedimentary in type, and the greater number are sands, sandstones, limestones, or dolomites. There are some cases where accumulation has taken place in finer grained rocks such as shales; more rarely, igneous rocks have become reservoirs of petroleum. These rocks vary considerably in structure and texture, and since their porosity is related to those factors it will be convenient to discuss them from that point of view. They fall into two main groups, unconsolidated rocks and consolidated rocks. Unconsolidated rocks are an aggregate of loose particles and are typified by sands and gravels. In a consolidated rock the particles are tightly packed and held together by some form of cementing material so that the mass as a whole has coherence. Sandstones, limestones, and shales are typical consolidated rocks. A table is appended giving representative figures for the porosity of some typical reservoir rocks.

Unconsolidated Rocks.

Unconsolidated rocks are essentially an aggregate of particles which are predominantly siliceous. These may vary in size from pebbles, or even larger, down to the finest silts, whilst their shape may vary from tabular to spherical. In general, however, most oil sands fall within much narrower limits both with regard to the size and the shape of their constituent particles. The distribution of particle sizes in any particular rock is very variable. In a well-graded deposit the greater number of the particles are of the same order of size, whereas in a poorly-graded deposit there may be particles of all sizes.

It is obvious that particles of this type cannot fit tightly together as would rectangular blocks, and therefore porosity must be developed to some degree in such a rock. The extent to which it is developed depends upon the grading, the shape, and the manner in which the particles pack together. In the case of spherical particles an analysis of the properties of the aggregate is possible and details of this may be obtained by reference to a paper by Graton and Fraser [3, 1935]. An important fact emerging from such an analysis is that the porosity of the aggregate is independent of the size of the spheres provided that they are uniform. The addition of either larger or smaller spheres will, however, tend to reduce its porosity. These facts, so easily demonstrated in the case of spheres, are fundamental factors governing the porosity of sands and may be expressed simply as follows: the more even the grading of a sand, the higher its porosity will tend to be. The fact that porosity is independent of the size of the grains, except in the case of the smallest, is of especial significance in reservoirs. A fine-grained rock may be equally as porous as a coarse-grained rock, and yet the former may not be so effective a reservoir as the latter on account of the difficulty which fluids may have in passing through the very fine pores and on account of the considerably greater surface area of the particles which retains a correspondingly greater amount of fluid on it. The importance of making permeability measurements as well as porosity measurements cannot be too strongly stressed. Some departure from the rule stating the independence of porosity on particle size is experienced in the case of very small particles. Their large surface area and low settling velocity introduce factors which tend to prevent them from packing together as tightly as coarser particles, and therefore the resulting porosity is higher than one would at first sight presume.

The effect of the shape of the particles on the porosity of a sand cannot be shown so easily. It is to be expected with angular particles that bridging takes place to some extent with the formation locally of larger voids. According to Fraser [2, 1935], who conducted experiments with particles of different shapes, angularity usually causes some increase in porosity, but ordinary, moderately well-rounded sands do not vary greatly in this respect.

Compaction is another factor for which it is difficult to make due allowance since representative samples of the deposit are but rarely obtained. Samples from a borehole are merely a heap of loose grains, and it is impossible to say whether or not they are in a state of maximum compaction when in the deposit. Measurements, therefore, must be made with the sample compacted to the highest degree possible and the result recorded as being the minimum porosity of the sample taken. It is probable in most cases that this approaches closely to the true value.

The porosity of spheres of a uniform size varies between 47·6 and 26% according to the manner in which they are packed together. Fig. 1 shows spheres arranged in the most compact form. The porosity of natural sands falls generally

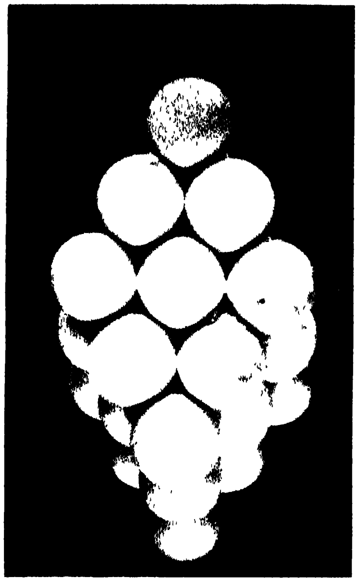

FIG. 1 Spheres arranged in the most compact form

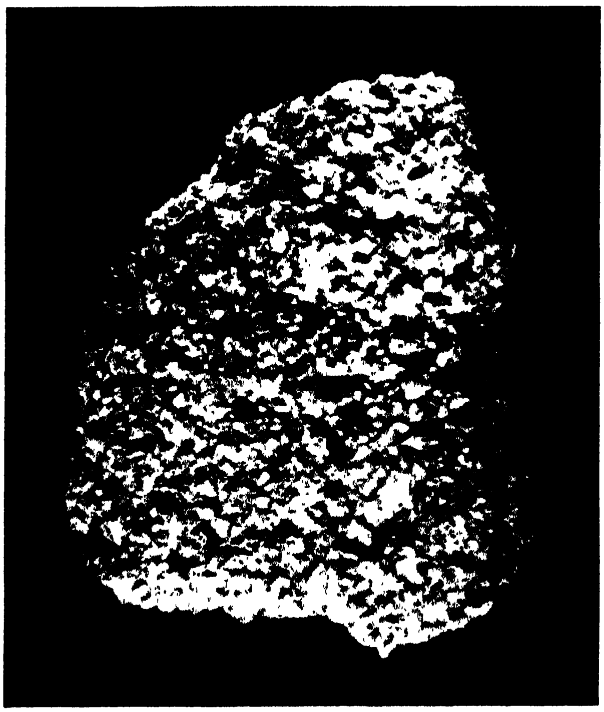

FIG. 2. Pechelbronn oil-sand. ×3

within the limits given above, and for normal, fairly well-rounded and well-graded sands it varies between 35 and 40%. Sands which are not so well graded have porosities of the order of 30%. To illustrate the effect of porosities of this order on the capacity of a reservoir the void space per acre of sand 10 ft. thick can be calculated. With a porosity of 30% it is 130,680 cu. ft. or 23,261 bbl., and with a porosity of 40% it is 174,240 cu. ft. or 31,015 bbl.

Consolidated Rocks.

The various types of consolidated rocks are best described individually, and as sandstones are more closely related in structure to the unconsolidated sands than are the other consolidated rocks, they may be dealt with first. A sandstone may be defined as a sand in the pore space of which there is sufficient cementing material, usually ferruginous, calcareous, or siliceous in nature, to give the mass coherence. The cement may either partially or wholly fill the pores. The porosity of the rock, therefore, is governed by the same factors as those governing the porosity of an unconsolidated sand, subjected to the additional factor due to the presence of the cement. A sandstone, however, is a competent rock, and as such it may be jointed and is also liable to be cracked and broken by stresses and strains of various origins. These stresses and strains may be external, the result of earth movements, or they may be internal, the result of crystallization of minerals from solutions which have entered the pores. The net result is similar and the cracks and fissures thus formed will give the rock an added porosity. In a well-cemented sandstone its porosity may be almost entirely due to such phenomena. The porosity of a sandstone may also be increased in certain cases by the leaching action of circulating waters on the cement. Some idea of the magnitude of the measurable porosity developed in sandstone reservoirs may be obtained by reference to the table.

The term 'limestone' may be extended for the present purpose to include true limestones, dolomitic limestone, and dolomites. The composition of these rocks varies widely and to some extent it has a bearing on their porosity. In certain cases a limestone may have a granular structure and so be comparable with a sandstone. The chief representatives of this class are chalk and oolitic limestones. A pseudo-granular structure is also developed locally in some dolomitic limestones due to the crystalline form of the dolomite. In other cases dolomitization may cause porosity to be increased to some extent due to shrinkage during the mineral change. This has been demonstrated by Parsons [8, 1922] in the case of the magnesian limestone of Derbyshire. The usual limestone reservoir rocks, however, have little inherent porosity, and their capability of storage is due mainly to two factors: (*a*) jointing and fracturing, and (*b*) solution.

The effect of joints and of fractures on the porosity of limestones is similar to that in the case of sandstones and other competent rocks which may have been shattered. The Asmari limestone, the reservoir rock of the Persian field, may be cited as a good example of this condition and has been described by Lees [5, 1933] as a normal, fine-grained rock with a lack of obvious porosity. A fresh core may sweat gassy oil, but mainly or entirely from cracks and small mineralized veins.

Limestones in which the porosity is due to solution undoubtedly form the most important class. Howard [4, 1928] considers that possibly 95% of the known limestone reservoirs owe their porosity to this cause. The effect of solution is varied; it may produce a honeycombed type of structure or it may be cavernous. In any case measurements are not possible.

Shales and similar fine-grained rocks present a difficult problem. In some cases the grain size is fairly uniform and they are then relatively porous. The size of the pores, however, is so fine that they cannot be reservoirs on that account. The ability of such rocks to act as reservoirs is due to the presence of bedding planes and to shattering with its consequent formation of cracks. Porosity measurements may therefore be very misleading and due attention should be paid to this point.

TABLE I

The Porosity of Some Typical Reservoir Rocks

Type of rock	*Formation*	*Field*	*Porosity*
SAND: 50% of the grains > 0·3 mm.	Upper Etchegoin, Pliocene	Elk Hills, Kern Co., California	24-35%
SANDSTONE: uniform, fine-grained, slightly dolomitic sandstone	Wilcox sand, Simpson formation, Ordovician	Gt. Seminole, Oklahoma	16%
SANDSTONE: irregular grains, average size 0·1 mm., siliceous cement	Whirlpool sandstone, Lower Silurian	Clinton-Medina fields, Ontario	10%
SANDSTONE: uniform grain size, well cemented	Bradford sand, Chemung formation, Devonian	Bradford field, Pennsylvania	11-17%
SANDSTONE: grain size mainly 0·1-0·25 mm., siliceous and calcareous cement	Woodbine sand, Upper Cretaceous	East Texas field	18-22%
SILTSTONE: siltstone and shale with numerous small lenses of sand	Bowdoin sand, Colorado Shale, Upper Cretaceous	Bowdoin dome, Montana	<10%
LIMESTONE: no signs of dolomitization	El Abra limestone, Lower Cretaceous	Tepetate, Mexico	5-12%
LIMESTONE: porous and, in some places, cavernous chalk	Selma chalk, Upper Cretaceous	Jackson field, Mississippi	5-20%
LIMESTONE: fine-grained, foraminiferal limestone	Asmari limestone, Lower Miocene	Masjid-i-Sulaiman, Persia	1-16%

As previously mentioned, igneous rocks are reservoirs in some fields. The lithology of such rocks varies considerably, but their porosity is due mainly to vesicular structure, jointing, fracturing, or any combination of those factors. As may be expected, the porosity of such a rock is very irregular and is not amenable to ordinary measurements.

In the above brief summary of the characteristics of the various types of reservoir rocks it has been shown how the porosity may vary with differences in lithology. The correct application of the results of porosity measurements is only possible when a knowledge of that variation is used in conjunction with the data available on the conditions under which the rock was deposited and its subsequent history. Thus in the case of a sand, the type of the deposit will throw some light on its horizontal extent and on the variation in grading. This in turn is of assistance in deciding to what degree the porosity may be relatively uniform and in what direction it may be expected to vary. For instance, where large sheet-like bodies of sand have been deposited off a shoreline regular conditions are usually developed parallel to the shore, whilst the greatest variations occur along a section at right angles to the shore. When dealing with cemented rocks it is more difficult correctly to apply the results of porosity measurements. A study of the lithology of the reservoir will indicate to what extent the rock is uniform. This will give some indication as to possible variations in the measured porosity. There must be considered in addition, however, the porosity induced by cracks, fissures, solution, &c., and this will figure in the measurements only in the case of the finest of the cracks. The measured porosity in such a case is therefore the minimum porosity of the rock. The history of the rock subsequent to deposition must now be considered. If it has been faulted, then the nature of the rock in relation to the degree of faulting may give some indication of the extent to which it has been cracked and broken. As already pointed out, in limestones the effect of solution is even more important than that of fractures. If there is evidence to show that the limestone has been subjected to the action of circulating surface waters, then one may expect solution, in most cases to some considerable degree, to have taken place. It is not possible to come to any conclusion concerning the porosity of such a reservoir as a whole. A similar conclusion is true in the case of shale and igneous rock reservoirs.

In view of the above facts it would seem that to strive for a high degree of accuracy in the measurements is not necessary for ordinary practice. Simplicity and ease of operation are of greater importance. Samples of consolidated rocks should be as large and as numerous as possible in order to reduce the effect of small irregularities. Many methods of making porosity measurements have been evolved, and references to these are to be found in the literature dealing with ceramics, refractories, water-supply, &c., as well as in that dealing with petroleum reservoir rocks. The basic principles are few, and it follows that these many methods are but adaptations from them, in some cases to suit special circumstances. Methods will be described here for measuring the porosity of both unconsolidated and consolidated rocks. They may be classified as follows:

A. Measurements on unconsolidated rocks.
B. Measurements on consolidated rocks.
  (1) Total porosity
  (2) Effective porosity:
    (*a*) Liquid absorption methods,
    (*b*) Gas expansion methods.

Before any measurements can be attempted it is necessary to remove what moisture, oil, and bitumen may be present in the sample. Water is removed by drying in an oven for several hours at 110° C. The oil and bitumen are best removed by extraction in a Soxhlet type extractor. Unconsolidated sands are placed in an extraction thimble of suitable size. Large pieces of consolidated rock call for a Soxhlet extractor made of metal. Extraction is continued until the returning solvent shows no sign of discoloration, a process which may take several hours. Suitable solvents are carbon disulphide or benzene.

A. Porosity Measurements on Unconsolidated Rocks.

The method recommended is similar to that described by Nutting [7, 1930]. The apparatus is merely a small cylindrical glass jar to which a flat cover fits with a ground joint—see Fig. 3. The volume of this vessel is determined

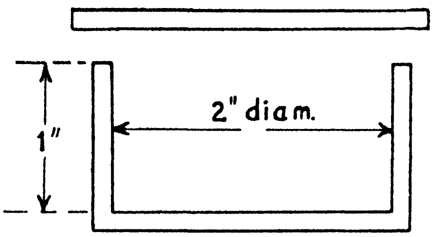

FIG. 3. Glass jar used in porosity measurements on unconsolidated sands.

and it is then filled with the sand, care being taken to compact the latter as much as possible, and its weight determined. The volume of the sand is calculated by dividing its weight by its specific gravity, and for most purposes it is sufficiently accurate to assume that the sand is entirely quartz, a value of 2·65 then being used. The volume of the vessel minus the volume of the solid particles gives the volume of the pore space.

B. Porosity Measurements on Consolidated Rocks.

(1) **Total Porosity.** The total volume of the oil- and moisture-free sample is determined by mensuration in the case of specimens of regular shape or by measuring the volume of water which it will displace if it is irregular. In the latter case it must be coated with an impervious medium such as wax before immersion, due allowance being made for the volume of the wax. The volume of the solid matter in the specimen is determined by weighing and then dividing by its specific gravity. Specific gravity measurements may be made with a small sample of the crushed rock in a pycnometer.

(2) **Effective Porosity.** (*a*) **Liquid absorption method.** This method, in brief, consists in causing a known volume of the rock to absorb a maximum volume of liquid such as benzene and then measuring the volume of liquid so absorbed. By this means the amount of pore space in free communication is determined. The apparatus required is a form of pycnometer, the method being described by Thomas, Chisholm, and Cameron [9, 1935]. A suitable form of the apparatus for general use is illustrated in Fig. 4. The specimen is placed in the vessel which is then evacuated to the highest degree possible. It is next inverted with the tube from the stopcock immersed in the liquid and the liquid allowed to enter. By means of weighings it is possible to determine the weight of liquid displaced by the solid rock and the non-effective pore space, and hence the volume of those items may be calculated. The total

volume of the specimen is determined as described in the method of measuring total porosity.

This method is suitable for hard, well-cemented rocks. If the rock is at all friable it will tend to disintegrate when liquid enters its pores, and hence for such rocks the gas expansion method should be used.

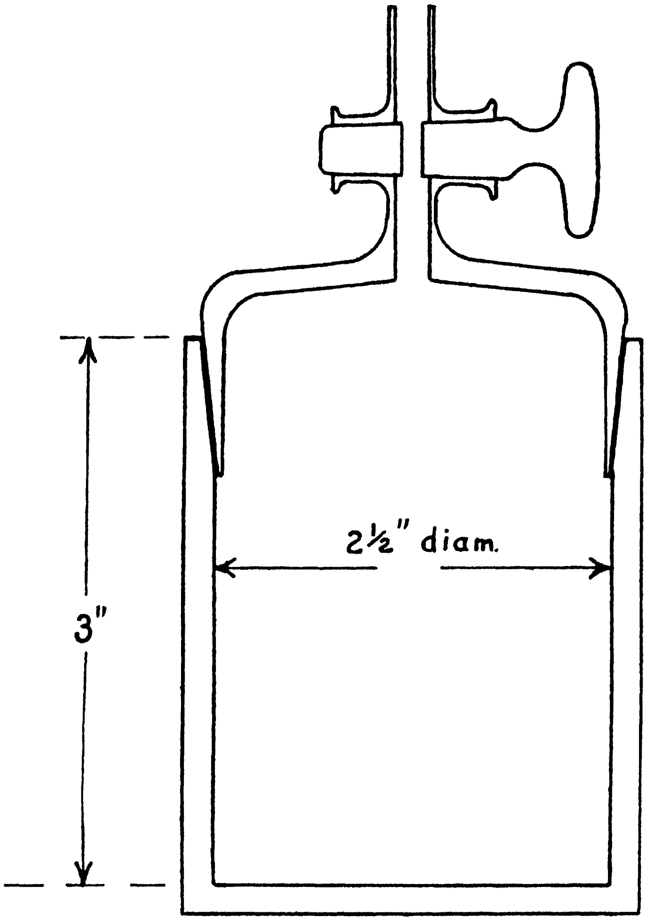

FIG. 4. Vessel for measuring porosity by the liquid absorption method.

(*b*) **Gas expansion method.** This method is an application of Boyle's law regarding the expansion of gases. If two vessels contain a gas at known pressures and the volume of one of the vessels be known, then the volume of the other may be calculated if the two vessels are placed in communication and the resulting pressure noted.

Many descriptions of suitable forms of apparatus have appeared, notably in publications by Coberly and Stevens [1, 1933], MacGee [6, 1926], Washburne and Bunting [10, 1922], and others. They may be classified into two groups, those in which the initial pressure difference is produced by compression, and those in which it is produced by exhaustion. An excellent example of the former type is described by Thomas, Chisholm, and Cameron [9, 1935]. The compression type of apparatus, however, has the disadvantage that the cover of the chamber containing the specimen needs to be secured in position by bolts, thereby causing the difficulty of ensuring that its volume shall not alter each time the cover is replaced. If, instead of compression, exhaustion be used, then a very simple apparatus may be designed, a suitable type being illustrated in Fig. 5. The main factor in design is the ratio between the volumes of the two vessels. With the specimen in place the volume

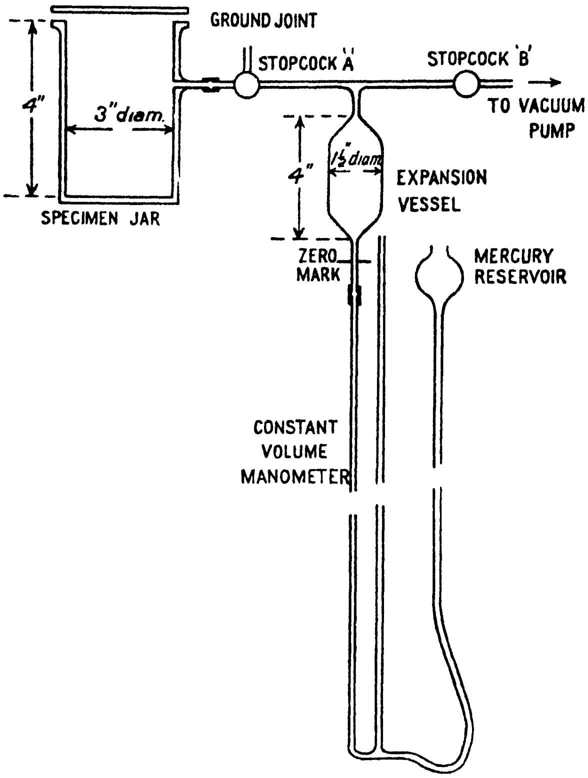

FIG. 5. Gas expansion apparatus for porosity measurements.

of free air space in each vessel should be approximately equal in order to minimize errors due to inaccurate pressure readings. The specimen should as far as possible fill the vessel, and therefore the second vessel should have a volume comparable to the effective pore space of the specimen. For general purposes this should be assumed to be 10–15%. If it is not possible to obtain a specimen which fills the vessel, the remaining space may be filled with sand and allowance made for its volume in the subsequent calculations. Care should also be taken to ensure that the specimen is quite dry, for otherwise considerable errors may be introduced by vapour. As in the case of the liquid absorption method, the volume of the solid matter plus the non-effective pore space is obtained. The total volume of the specimen is determined by mensuration or by the displacement of water.

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THE ORIGIN OF PRESSURE IN OIL-POOLS

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THE normal oil-pool is an association of gas, oil, and water in a porous rock. The gas may be entirely dissolved in the oil or it may exist partly in this state and partly as free gas above the general oil zone. The oil lies above the water, and usually the line of demarcation between the two, the 'edge-water' line, is clearly defined. The whole of this liquid and gas is under considerable pressure, which is usually sufficient to force the oil to the surface in the early stages of a developing field. Various terms have been used for this pressure: rock pressure, formation pressure, reservoir pressure, &c. Probably the term reservoir pressure is the most appropriate to a discussion of the pressures within the reservoir, for such terms as rock pressure may be used more strictly to indicate pressures within a rock mass by virtue of its own transmission of pressure. It must be admitted, however, that there is no common agreement on this point, and the terms are often used synonymously.

Before proceeding to a discussion of the origin of these pressures it is advisable that some attention be given to the actual conditions in individual fields and more particularly to the pressure declines which occur as these fields are exhausted. The gas, oil, and water in the reservoir are subjected to the same physical laws throughout their confinement, but the conditions are necessarily complex and changing, and it is this variability which determines the behaviour of the reservoir contents at different periods.

As a general rule the pressures within a given oil-pool tend to increase with depth, so that as deeper formations are penetrated the reservoir pressure of each successive older formation tends to increase. Thus it becomes, in a very general way, a function of depth.

In the Muskegon field of Michigan the following data illustrate the relationship of depth to initial reservoir pressures [9, 1935]. The fourth column gives for comparison the calculated pressure of a water column at the same depth.

TABLE I

Formation	*Depth, ft.*	*Initial pressure, lb. per sq. in.*	*Calculated hydrostatic pressure, lb. per sq. in.*
Upper Traverse	1,590–1,650	630	691–718
Lower ,,	1,810–1,890	710	787–822
Dundee	1,960–2,030	920	850–881
Monroe	2,160–2,230	940	942–972

As a further instance of the increase of reservoir pressures with depth the case of a gas-well at Clarksville in Arkansas may be cited [3, 1935].

TABLE II

Sand	*Depth, ft.*	*Rock pressure, lb. per sq. in.*
Russell	2,875	770
Qualls	3,025	810
Kirwin	3,165	1,125

There are, however, too many exceptions to this general rule to allow it to be regarded as more than an approximation. Depth alone cannot be the sole determinant of rock pressure. The following reservoir pressures were measured on one lease of the Seminole field, Oklahoma [8, 1931].

TABLE III

Formation	*Depth, ft.*	*Pressure, lb. per sq. in.*	*Equivalent head of fresh-water, ft.*
Miscrer Sand	3,967	988	2,276
Hunton Lst.	3,980	1,520	3,520
Simpson Dol.	4,068	1,152	2,654
1st Wilcox	4,124	637	1,467
2nd Wilcox	4,217	800	1,843

It will be noted that the deeper Wilcox Sands have much lower pressures than the overlying formations and, furthermore, there are large differences in pressure in formations separated by only a few feet of sediments.

Variations from the normal pressures may be either upwards or downwards. Heroy [5, 1928] quotes Orton as having noticed an instance of a pressure of 1,540 lb. per sq. in. in a well only 2,370 ft. deep which he was unable to explain as due to artesian head. Other cases of abnormally high pressures will be given later. Instances of abnormally low pressures are widespread. In the Cleveland field of Ohio the initial reservoir pressure for the Trenton Limestone at a depth of 4,500 ft. was only 37 lb. per sq. in. [4, 1931]. In the Panhandle field the reservoir pressures are subnormal [2, 1935], being usually less than one-half of the normal hydrostatic head. Krejci-Graf [7, 1930] gives an instance at Boldesti, Roumania, where the pressure of a sand at 1,541 metres was 185 atm., whereas that of a deeper sand at 1,681 metres was only 89 atm., equivalent to an increase in pressure with depth of only 23·7 lb. per sq. in. per 100 ft.

As an actual fact there is no constancy in the rate of pressure increase with depth. The following instances indicate this point [4, 1931].

TABLE IV

Locality	*Formation*	*Depth, ft.*	*Initial pressure, lb. per sq. in.*	*Average pressure increases per 100 ft., lb. per sq. in.*
Butler, Pa.	Hundred-foot Sand	1,400	780	56
Barbour Co., W. Virginia	Benson Sand	4,090	1,800	44
Woodsfield, Ohio	Berea Sand	2,090	710	34
,, ,,	Salt Sand	1,295	280	22
Butler, Pa.	Fourth Sand	1,568	225	11
Cleveland, Ohio	Trenton Lst.	4,500	37	0·82*

Pressure Changes During Production.

The history of the pressure changes as a field is being developed may depend on a number of circumstances. In some gasfields the decline in pressure appears to be directly proportional to the depletion of the gas in the reservoir. Such a pool acts as though it were a limited quantity of gas compressed into a container of fixed volume. The gas seems to be the seat of the pressure, and as the gas is

exhausted the pressure drops proportionally. This condition can be more closely followed in a simple gas-pool than in one containing both oil and gas, for in the latter the conditions are complicated by gas dissolved in the oil. As the pressure declines with gas depletion a certain amount of replenishment takes place by gas coming out of solution and the pressure decline is therefore partially checked. Here again, however, the conditions are governed strictly by physical laws, but the introduction of an additional phase, solution, into the conditions merely adds to the complication.

There are, however, some oilfields where the drop in pressure during the exhaustion of the oil and gas is not at all commensurate with the depletion of these materials. The wells change from oil-wells to water-wells with very little change in pressure, and in certain extreme cases the whole field goes progressively to water without any marked decline in the pressure. Such fields are in strong contrast to those considered above, and it is difficult to believe that the control of the pressure is the same in both cases.

The two conditions referred to above are symptomatic of the behaviour of most oilfields. As a general rule their behaviour lies between these two extremes, but there is on the whole a tendency to approach the first condition rather than the second. In other words, the depletion of the oil and gas leads to a gradual decline in pressure. The source of the available pressure generally lies in the gas rather than in the liquids, and this reserve of energy is conserved as far as possible in modern methods of exploitation.

It may also be noted that the two types of pressure conditions in oilfields appear to be closely related to the freedom of movement of the edge-waters. In most oilfields this movement is distinctly limited. Partial exhaustion causes a rise in the edge-water table, but complete exhaustion leaves the field with a considerable area under negligible pressure into which the edge-waters have not penetrated. There are only a few oilfields in which water completely displaces the oil and gas in the last stage of exhaustion, just as there are only a few fields in which the pressure is maintained throughout the life of the field without artificial means of pressure maintainance. As a counterpart to the latter condition there are some oil-pools in which no edge-water movement of any kind can be noted throughout the exhaustion of the field. In such fields the seat of pressure obviously cannot lie in the water.

These two types of behaviour in oilfields find a simple explanation in the physical conditions which control the gas, oil, and water.

An oil-pool is a quantity of gas and oil lying in a porous receptacle and usually associated with a variable quantity of water. The reservoir rock is both porous and permeable and it is usually completely enclosed in an impermeable envelope. There is one important and very variable factor in all reservoirs, i.e. their relative size. Some may be quite small and the total void space can be measured at the most in a few thousand barrels. They may be too small to provide sufficient oil for a single commercial well, in which case only a succession of such bodies can create a successful field. Other reservoirs are merely portions of widespread rock masses in which the volume of pore space in physical continuity may exceed in volume by many thousands of times the volume of oil and gas in the reservoir. The excess volume in such a case is occupied by water.

The variation in the volume of the reservoir and in the ratio of the combined oil and gas volume to water have an important bearing on the behaviour of the oil and gas during exhaustion of the reservoir. An oil and gas zone in a limited reservoir will obviously occupy a considerable proportion of the reservoir capacity. The depletion of the oil and gas will leave nothing but the water to occupy the space, and the supply of water being limited, there is a resulting drop of pressure in proportion to the gas and oil depletion. On the other hand, an oil-pool in an almost unlimited reservoir rock bears but a small ratio to the total void space in intercommunication. There are extraneous factors which may affect the pressure within this reservoir rock, and these will communicate themselves to the water zone in addition to the pressure due to the gas- and oil-pool. The edge-waters of such a pool are therefore under pressures from several sources, and if the oil and gas in the pool are removed, the extraneous sources of pressure cause water movement until a new equilibrium is attained.

Thus the variable behaviour of different pools may be largely explained by the differences in size of the reservoirs, and when it is remembered that the permeabilities of the latter may also differ very markedly, the variable time lag required for these readjustments finds an adequate explanation.

It is important to note that oil and water are relatively incompressible. They cannot, therefore, in themselves maintain a condition of pressure if even a slight expansion be allowed in their volume. They can only exert continuous pressure where they transmit pressure from a contiguous source such as a connected gas-pool, or by the replenishment of the fluid pressure by access of further liquid, as occurs in artesian conditions.

Some slight alterations are possible in the pore space of reservoir rocks, but these are likely to be small or at any rate their variations will be slow. No sudden change in pressure can therefore be produced by sudden changes in the pore space, though there is reason to believe that in some rocks changes in the porosity may be induced by collapse as a result of diminution in pressure.

Gas, whether free or in solution, is the important medium whereby pressure can be fossilized and maintained. The enormous volume changes associated with alterations in pressure conditions enable the gas to portray the pressure conditions to which it has been subjected, so long as pressure relief has not been allowed to intervene. When, therefore, we inquire into the origin of reservoir pressure in oilfields, a considerable part of the discussion centres on the origin of the gas pressure.

Possible Sources of Pressure

Pressure due to a Water Column.

The simplest and most obvious source of pressure in a rock within the earth's crust is that due to the head of water filling the pores of the rock and in communication with the surface. Such a water column must exert its equivalent pressure and will produce a corresponding flow if the pressures in the water zone are not balanced. The simplest example of this is the condition in an artesian well where a water-saturated permeable rock folded into the form of a basin gives a high pressure in the bottom of the basin due to the weight of the water column on the flanks.

Edward Orton, in one of the classics of petroleum literature [10, 1888], made out a strong case for this theory. He pointed out that the gas, oil, and water are under pressure and the oil- and gasfields are surrounded by rocks saturated with water under pressure. The rock in the case he was discussing outcropped some distance away and must have

been fed with meteoric water at the surface. It is interesting to note the inferences which he drew as to the probable attributes of pressures due to such conditions. The rock pressure will increase with depth and will depend on the differences in height between the reservoir rock and its corresponding outcrop. The pressure will continue with unabated force until the last stages of production, and the gas and oil will ultimately be replaced by water. The supplies of oil and gas will be limited, and once the water column has risen in the field the life of the latter is at an end.

Applying these conclusions to the history of oilfields in the period since Orton first put them forward, it is interesting to note that they apply in full to only a few cases, though they are partially applicable in a number of fields. In some of the Mexican oilfields the pressures appear to show very little decline during production and the oil is rapidly replaced by salt-water as the edge-waters rise. The ultimate movement of the latter is very considerable and the whole field tends to become flooded. In most oilfields some edge-water movement occurs during production, but the movement is more restricted in its general scope. There can be little doubt that the rapid pressure declines in many oilfields have resulted from faulty methods of production, but that does not alter the fact that the normal course of most oilfields is for there to be a drop in pressure as the field becomes exhausted, until finally the pressure becomes negligible. This, and the limited nature of the edge-water movement, indicates conclusively that for such fields the seat of the pressure cannot lie in the water which surrounds the pool. Furthermore, the examples cited above of the anomalies in the pressures of neighbouring sands and the variable rate of pressure increase with depth indicate that some other sources of pressure must be available. Within a limited sand lens surrounded by clays it is difficult to see how a water head could be developed unless we ascribe a condition of permeability to the formations, which is in conflict with their physical properties. The majority of oil reservoir rocks are somewhat limited in their lateral extent, and in such bodies artesian pressures are unlikely to occur. In the case of the extensive reservoir rocks there is no reason to exclude the development of pressures due to head of water. In such cases it is inevitable that the extensive water sheet will be under pressure, but whether it will be entirely due to the head of water or to other conditions will depend on the circumstances. The fact that edge-waters are normally saline, while artesian waters are fresh, does not prove that the pressures in the former cannot be due to a head of water. The flushing of the saline waters out of the formations can only take place when there is sufficient erosion to involve extensive circulation of the waters within the formation.

Pressures due to the Weight of Sediment.

During the early stages of sedimentation the argillaceous beds undergo compression as the overlying sediments add to the load. This diminution in volume is associated with the expulsion of water and any other fluid or gas which may occur in the clays. The compression is resisted by the gel strength of the clays and by their increasing impermeability, which limits the ease of water movement. The pressures within this compacting medium must therefore reflect the weight of the superincumbent mass, and as the fluids can only escape along certain restricted paths, the pressures on the clays will be partially transmitted to the fluids within them. As the process of compaction advances the outflow of the compaction fluids becomes more difficult, so that the pressures in the fluid and in the sediment itself become practically identical.

The plastic clay and its own compaction fluids develop a pressure gradient downwards by virtue of their combined weight, and the pressures of the liquids or gases in any completely enclosed sand bodies will be determined by this pressure gradient even though the sand itself may not be compressible. There are some oilfields in exceedingly young strata which appear to simulate these conditions. At Goose Creek in the Gulf States fields of Texas the formations are young and poorly compacted [11, 1926]. The clays contain as much as 30% of water, and the sands are soft, poorly consolidated, and lenticular. Thus the general fluid movement is greatly limited by the clays. Commercial oil production has been obtained at depths varying from 1,000 to over 4,000 ft. in strata varying in age from Pleistocene to Upper Oligocene. During the extraction of the oil and gas subsidence of the surface has occurred coinciding with the area of extraction. The amount of subsidence is approximately one-fifth of the volume of extracted materials. This appears to be a case of accelerated compaction due to the loss of pressure in the oil sands caused by drilling. The lower pressures thus induced have allowed further compaction in the clays around the sands, and the surface has in consequence subsided.

So long as the general mass of sediments is plastic the pressures are commensurate with the weight of the overlying materials, and both fluid and rock substance contribute to the pressure. In this case the term 'rock pressure' would give a true picture of the conditions. The fluids within this medium find it difficult to force an exit, and their pressures are therefore closely comparable to that of the enclosing medium. If, however, there be a sand body or other extensive permeable rock which provides an easy passage for fluids out of the compacting medium, the pressures within this sand body may be considerably below the average pressures for an enclosed lens at the same depth. The presence of such a sand body may create a low-pressure system within the fluids in the neighbourhood. In other words, the pressures within the sands depend in part on the pressures within the compacting medium, but they are also influenced by the ease of egress of the compacting fluids. This latter point will explain some of the differences in the pressures in neighbouring sands. A limited sand mass surrounded by a thick sheath of clays will reflect more truly the actual pressure in the clay medium than a sand mass which extends into regions of lower pressure and which will therefore be controlled by the latter.

It has been said that the pressures built up in this manner will be commensurate with the weight of the overlying material. If the substances were true liquids the pressures produced would be equivalent to the head, but the materials are not liquid, and as they get more compressed they depart more and more from this condition. The result is that the rock pressure produced is but a fraction of the weight of the sediments, and as the rocks become more rigid this departure becomes more pronounced. Turning our attention for a moment to the fluids within the sediments, we may consider that the pressures within them are dominated by two factors, the compression due to compaction on the one hand, and the resistance to outflow on the other. These tend normally to grow together so that the pressures in the fluids also grow, but compaction becomes more difficult in the later history of the sediments, and it is then that the

effects of differences in the ease of exit become more marked. Some reservoirs, completely enclosed in impervious material, may build up pressures to abnormal extents, whereas others from which fluid egress is possible have more limited opportunities for pressure increase.

Summarizing the above conditions, the theory of compaction pressures presupposes a condition of limited permeability within a mass of sediments compressing under their own weight. The gas, oil, and water trapped within limited reservoir rocks are subjected to a pressure which reflects this compression and is a function of the total weight of the overlying sediments. The ratio of this pressure to the total weight depends on the circumstances of enclosure of the reservoir.

Pressures due to Diastrophism.

The pressures within the earth's crust are the result not only of the weight of the overlying rock mass, but they also reflect the conditions of stress within the crust itself. Where such stresses are compressional the rocks are deformed unless they have sufficient strength to resist the stresses. Lateral pressure, therefore, continues the process of rock compression begun by compaction, and the clayey strata may be still further squeezed with a resultant diminution of the pore space. The effects will simulate those of compaction, and so long as the rocks are not disrupted and new exits for fluid opened, the pressures built up may be abnormally high. Some interesting examples of abnormally high pressures may be due to this influence. At Khaur the pressures recorded are about 3,000 lb. per sq. in. in excess of the normal hydrostatic head [6, 1934]. The theory of inherited water pressure requires the Murree Series to have been some 6,000 ft. below their level of exposure at the time when the fluids were sealed off. It seems more likely that the pressures are due to the influence of the stresses indicated by the isoclinal folding north of Khaur.

When diastrophism proceeds to the stage at which the rock masses become fractured and fissured, the new zones of permeability give relief of pressure to the imprisoned fluids. Extreme folding, therefore, except in the case of exceedingly plastic formations, leads to excessive vertical migration and loss of pressure. This is largely the result of the gradual change in the physical character of the rock masses involved. The plastic characters become replaced by solidity, and the more rigid materials fracture under extreme stresses.

It is important to note one other aspect of the change in rock character from plasticity to that of a true solid. The strength of the clays is greatly increased by this process, and they become capable of resisting exceedingly high pressures. Not only can they protect the gas and oil in an enclosed sand from increase in pressure, but they can also prevent its depletion. This results in a condition of fossilized pressure wherein individual sands can be protected from loss of pressure during denudation by the compactness and strength of the surrounding rock mass.

Pressures due to the Generation of Oil and Gas.

While a mass of sediment is plastic and contains fluids in a state of movement it cannot retain within itself a condition of local high pressure. When, however, it has become more rigid and the permeability within the mass has become restricted, local conditions which lead to the generation of pressure can exert a permanent influence.

The possible causes of such local generation of pressure are: the formation of oil and gas; the increase in total volume of the hydrocarbons due to molecular break-down, or the reduction in pore space by cementation, &c. On the other hand, a reduction of pressure could be due to: the polymerization of hydrocarbons to types of higher molecular weight; chemical alterations such as asphaltization, or reduction in water content by the absorption of water into the clays to form new minerals.

Dealing first with the changes due specifically to the oil and gas content, it is reasonable to suppose that if oil generation continues after compaction has attained its maximum there will be considerable generation of pressure in the formations as a result of the volume increase which takes place when organic matter is changed into oil and gas. The writer is inclined to doubt whether the processes of oil generation occur at so late a stage, but there is a large body of geological opinion which supports these views, and until the matter is settled there can be no reason to preclude this as a fundamental cause of gas and oil pressure. If the process of oil generation takes place in a confined space and the rocks are sufficiently strong to support it, there will be an automatic increase in pressure as oil and gas are formed, for the process involves an increase in volume. Such pressures could only be preserved in a medium which was surrounded by an impervious envelope. If this were not the case, the pressure effects would be dissipated by fluid movement. It is for this reason that the writer would exclude from consideration any accumulation of pressure arising from processes of oil generation during the early phases of compaction. If oil and gas are formed by destructive distillation of organic matter within the crust, a considerable amount of pressure will be generated as a result of the chemical changes. The writer is not concerned here with the question whether such processes do take place, or whether the metamorphism is due to temperature or pressure. These matters belong to another field of inquiry.

Once the oil and gas have been formed in the sediments there are still many processes of molecular change which may and probably do take place in them. These include a further break-down of the higher molecular weight hydrocarbons accompanied by the formation of a large proportion of gas. There has always been a school of thought which considered that this process has been responsible for a larger proportion of gas in the Lower Palaeozoic fields than in the younger formations. The process would be analogous to the cracking process in a refinery, though the conditions would not necessarily be the same.

The processes of chemical alteration in oil and gas over long periods of time have not been thoroughly investigated. Barton [1, 1934] has investigated the Gulf Coast crudes and concludes that deep and prolonged burial results in the break-down of naphthenic hydrocarbons and the production of normal paraffin types. Such changes would undoubtedly be associated with volume changes and would affect the pressure in a restricted reservoir. There is also the possibility that polymerization rather than dissociation may occur in some reservoirs, in which case the pressure will be correspondingly reduced. We are on firmer ground when it comes to a discussion of the changes which occur in a reservoir as a result of deep-seated weathering. These matters will be referred to later.

Effect of Temperature Changes on Pressure.

There is one important aspect of the reaction of oil and gas to physical changes in the reservoir which must have a considerable effect on the pressures. This lies in the

changes in temperature to which the gas must be subjected by increase in sedimentation causing a rise in temperature or by denudation causing the reverse. If we assume that the normal rise in temperature in such sediments is 1° C. for 200 ft. of cover, the addition of 10,000 ft. of sediments would increase the temperature by 50° C., which would increase the pressure of any confined gas by about 20%. If, furthermore, the gas is associated with oil, it will come out of solution and the pressure will be correspondingly increased. Temperature changes modify the gas pressures in accordance with normal physical laws, but by altering the gas solution equilibrium they also change the quantities of free gas available in the reservoir.

The effect of denudation will obviously be in the reverse direction to that of sedimentation, and there must be slow, but none the less definite, changes in the pressure of an oil and gas pool as the thickness of the cover is reduced.

Other causes of temperature changes in the rocks—diastrophism, igneous intrusion, radio activity, &c.—will have corresponding influences. Igneous intrusion has occurred only in a few oilfields, of which Mexico is the best example. It is probable that in this case the effects of intrusion have not been limited to normal temperature changes, for there have apparently been metamorphic effects which have altered the volume of the pore spaces in the reservoir rock, and the peculiar chemical constitution of the gases associated with the oil which contain large quantities of carbon dioxide may be ascribable to the igneous activity. It is probable that in these Mexican examples the normal oilfield conditions have become modified by the proximity of igneous activity, and the pressure conditions due to both sets of phenomena are merged in the oilfield reservoirs.

Pressure Changes due to Mineralogical Alterations in the Oil-bearing Strata.

Once the sedimentary strata have been thoroughly compacted and the clays, &c., around the porous reservoir rocks have become impervious, the pressure in the latter must be a function of the quantity of water, oil, and gas available and the volume of the pore space. Any factor which alters either of these two features will alter the pressure.

We have considered already the alterations in the oil and gas. There remains, however, the consideration of any possible changes in the pore space of the reservoir and the quantity of water within it, on the principle that the oil and gas must occupy the void space unfilled by the water.

The volume changes in the pore space may be produced by the precipitation of cements or salts in the pores of the rock. The volume of free water may be reduced by the adsorption of water into the surrounding clays to form low-temperature micas.

The first of these processes needs no comment, but it is probable that it will only occur to a limited extent unless there is complete freedom of movement in the water, a condition which is not allowable in most cases. With regard to the adsorption of water into the clay bodies, there are in certain oilfields, notably Pennsylvanian, constant references to so-called 'dry sands'. In these sand bodies the water pressure has been so reduced that the sands act as water absorbers and their fluid pressure is negligible.

Whatever may have been the original condition of the sands, it is clear that the pressures have fallen considerably. The explanation of such conditions in an enclosed reservoir is not easy to find, but it seems possible that there has been an absorption of water into the clay mass. If this took place over a sufficiently wide area, even to only a limited extent, the water sand would automatically lose pressure unless the loss were counterbalanced by the inflow of further oil and gas. There are good reasons to believe that there is considerable scope for mineralogical reconstitution of the clays within the earth's crust, and, once the water held in the clays has been exhausted, the water in the neighbouring sand bodies will be drawn upon for the process. Such changes in water content would have no effect on the pressure unless the whole mass of sediments were compact and free from connexion with extraneous water bodies. If these conditions obtained, the pressures in the sands would undoubtedly drop. One of the curious features about nearly all oilfields is not that the pressures are so high, but that they are considerably lower than we should expect on the principles set forth in the earlier sections. This water adsorption may be a more general process than has been recognized, and it may be a general process of pressure reduction in reservoir rocks. If this is so, it may have some bearing on the anomalous pressures in sands, for the subsequent pressure reduction due to water adsorption would depend on the volume of the reservoir and the nature of its clay envelope.

Pressure Reduction due to Denudation.

In the preceding sections the various factors which have built up and subsequently modified the pressures in oil-bearing formations have been discussed. There remain to be considered the general processes of pressure reduction which are associated with denudation.

It is normal to consider weathering and denudation as a superficial process, but in so far as it affects oil and gas it may penetrate thousands of feet into the crust. Many an oil and gas seepage is connected with oil at great depth, and many an oil sand has been altered to a tar sand to a considerable depth underground by processes of change comparable to normal weathering.

The changes are aided by the presence of fractures or other channels which allow gas and oil to escape, and permit the introduction of water carrying bacteria or salts in solution which react with the oil and gas to form asphalts.

Intense diastrophism which folds and fractures the rock masses greatly facilitates the escape of the oil and gas, and therefore it leads indirectly to large drops in pressure. However, the production of new zones of permeability works both ways, and the incursion of water from the surface, which is accelerated by such conditions, leads to the development of water pressures due to the normal hydrostatic head. Indeed, there are many cases where the presence of hydrostatic pressure is probably a secondary phenomenon introduced by the progressive effects of denudation and succeeding the condition of original enclosed pressures which was associated with the formation of the oilfields.

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For further literature see the References of the article on 'The Migration of Oil' by Professor V. C. Illing.

SHORELINES AND LENTICULAR SANDS AS FACTORS IN OIL ACCUMULATION

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ANCIENT shorelines may be significant in connexion with the accumulation of oil and gas either as being places where exceptionally rich organic sediments are deposited, or as being places where porous sand deposits are formed which may later become oil or gas reservoirs.

The problem of the occurrence of oil accumulations in lenticular sands is closely bound up with that of the relationship of oil to ancient shorelines, because many of the sand deposits close to shore are characteristically lenticular.

Is it true that deposits laid down close to the shore are characteristically rich in organic matter which might become the future source of oil and gas? Several geologists have thought so (Jones [8, 1920], Branson [3, 1926]), and have even argued—on account of the supposed restriction of oil accumulations to the vicinity of rich organic source materials and of the supposed richness of near-shore deposits—that prospecting for new reserves is hazardous except in regions where the sediments to be tested were deposited in a near-shore environment.

A world-wide study of the organic contents of recent sediments by Trask [19, 1932] has shown that rich organic 'source materials' are by no means confined to the neighbourhood of the shoreline. Trask's results have such an important bearing on our problem that some of his most pertinent observations and conclusions are abstracted briefly in the following paragraphs.

First, it is important to bear in mind that the place where marine life is most abundant is not necessarily the place where the richest organic sediments accumulate, for organic life is light in weight and can be transported easily by currents to points that may be far removed from the localities where the plants or animals originally lived. Furthermore, on account of its lightness the inorganic matter tends to be deposited with the finer organic materials in places least disturbed by waves or currents.

Consider first the distribution of marine life. The shallow water near shore teems with life—both plant life and the animals that feed upon it. The larger forms of marine plants—the marine algae, or seaweeds—live mostly in the shallow water near shore through which sunlight can penetrate. The microscopic plants and animals, however, are not so closely restricted. They swarm in the near-shore waters, but are even more abundant off shore wherever there is an upwelling of cold water from the depths of the ocean such as occurs along the margins of ocean currents flowing parallel to the shore; along the outer margins of the continental shelves; or over other submarine escarpments. In short, life which might be the source of rich organic sediments may be as plentiful a hundred miles or more out to sea as along the shore.

As to the actual distribution of sediments rich in organic matter, Trask found that the abyssal deep-sea sediments are uniformly lean in organic matter, but that on the continental shelves and generally within 100 to 500 miles from shore, depending on the topography of the ocean bottom, no correlation could be made between richness in organic matter and nearness to the shore. The rich deposits within that zone are characteristically in the deeper basins or in any other places protected from wave and current action. In these protected spots the light-weight organic material accumulates with the finer inorganic sediments. Lagoons behind off-shore sand bars contain rich organic sediments in some instances, and in others they do not, depending on a variety of conditions affecting life and sedimentation.

In the light of Trask's results, it seems safe to say that in so far as the generation and accumulation of oil and gas may depend on the presence of sediments rich in organic matter, there is no reason to expect such accumulations to be confined to sediments deposited near the shore. Oil- and gas-pools may be expected to occur anywhere in a belt which is *within reach of migration* from adequate deposits of organic sediments whether those were laid down in lagoons close to shore or in deeper basins many miles out to sea.

In the case of shallow epi-continental seas such as those which covered much of North America during the Palaeozoic era, it is probable that no part was deep enough to be out of the zone in which rich organic 'source' sediments might accumulate. It is even probable that in many instances the deeper spots may have been the most favourable for the deposition of such sediments because of their being less disturbed by wave and current action. Trask found such to be the case in several relatively shallow enclosed seas such as Lake Maracaibo.

Relation of Lenticular Sands to Shorelines

The wave, current, and tidal activities characteristic of a shoreline produce concentrations of sand of lenticular character which, in so far as they are formed in the region where rich source rocks are also likely to occur, are especially favourable sites for the accumulation of oil and gas.

Lenticular sand bodies developed along a shore may be classified into (*a*) shore bars, spits, and hooks; (*b*) off-shore bars, generally separated from the mainland by shallow lagoons; and (*c*) sub-aqueous bars formed by the strewing of sand along the sea bottom by currents, and perhaps in some cases by wave action during the greatest storms.

Off-shore Bars or Barrier Beaches

The off-shore bar is commonly formed along gently shelving shores. Such bars are straight and long, generally rather narrow, and are interrupted at intervals by tidal inlets. Because prevailing winds are often diagonal to the shoreline, off-shore bars commonly are offset at the tidal inlet in such a way that the bar on the windward side of the inlet lies a little farther out to sea than that on the leeward side. Individual bars range in length from a mile or two to a hundred miles or more along modern coasts, and presumably they had a similar range along ancient shores.

The preservation of off-shore bars so that they can later serve as reservoirs for oil and gas requires somewhat special geological conditions. In the ordinary evolution of a coast-

line, if the land is slowly sinking, the bars tend to be pushed gradually backward rather than to be buried and preserved. If the land is slowly rising, the bar becomes exposed to erosion and new bars are built farther off shore. Preservation of such bars and their burial when the sea again returns over the area requires either that the wave action be very weak as the sea returns, or that the bars settle and become buried by alluvial material before its return. Whatever the process, it is evident that such bars can be buried and preserved, for we actually find them, as, for example, in Greenwood county, Kansas.

Sub-aqueous Bars

Sub-aqueous bars are not so well known. Soundings record areas off shore in which the bottom is composed of sand and other areas in which it is mud. These areas tend to be elongated and distributed parallel to the shore, but they are more irregular than off-shore bars.

Considerable evidence indicates that storm waves stir the bottom to depths as great as 600 ft., and in 200 ft. of water pea-sized gravel has been found in suspension 24 ft. off the bottom after a gale (Borley [2, 1923]). Whenever sand is lifted off the bottom by wave action it can be carried along, at least for a short distance, by any tidal current or undertow that happens to be moving. Thus it comes about that even weak currents are capable of strewing sand over the sea bottom, presumably stringing it out more or less in the direction in which the currents are moving.

Charts of the North Sea bottom accompanying Borley's report show a distinct corrugation of the ocean bottom off the English coast which appears to represent sub-aqueous bars trending approximately parallel to the shore. They are on a larger scale than most of the sand lenses with which the petroleum geologist has to deal, but it seems probable that they are formed in the same way.

The sub-aqueous bars cannot be expected to be as definite in form or as thick as the off-shore bars, nor to show the definite thickening at the top characteristic of off-shore bars.

Irregular Shore Bars and Spits

Minor shoreline deposits such as spits, hooks, tombolos, and cuspate forelands are commonly built out into deeper water, and consequently at least their bottom parts are likely to be preserved (Johnson [7, 1921]). These would form isolated lenticular sand bodies of variable, and in general unpredictable, form, dimensions, and distribution (Brewer [5, 1928]). As Johnson has pointed out, they would appear in many cases as nodes of thicker sand projecting downwards below the base of a sheet sand.

Tidal Inlets

Along a coast defended by barrier beaches, the individual sand bars are broken at intervals or separated from each other by tidal inlets through which the lagoons behind the bars are filled and emptied twice each day. On account of the restricted width of the inlets, the currents through them are swift and scour deeply. If physiographic conditions change so that an inlet is abandoned and silted up, a thick body of sand may be preserved which will lie at right angles to the trend of the bars; will have a channel form; will cut down deepest and may be thickest in the middle of its length; will be relatively short; and may merge, on the lagoonward side, into the irregular sands of a tidal delta.

Channel Sands

Another type of lenticular sand body not so closely restricted to the shore, though generally formed in an environment not far from the shore, is the channel sand.

Channel sands may be the fillings of river channels, delta distributaries, tidal channels in lagoon deposits, or of channels formed by the deep scouring which is common at tidal inlets.

Each type of channel has a distinctive configuration which can be used in determining its type. This, in turn, is essential information if one is tracing the course of such a channel by means of well records. The tidal river or delta distributary channels swing in broad, smooth curves and maintain their width for long distances; tidal channels meander intricately, branch, and are likely to taper out abruptly; the tidal inlet channel is short, deep, deepest in the middle of its length, and is disposed more or less at right angles to the shore at the time it was made.

Dune Sands

Another type of sand deposit which may make lenticular sands is the sand dune or the sand-dune area. Such deposits, if buried without serious modification, are irregular in pattern. The sand is highly irregular in thickness, and is characterized by an irregular top without distinctive pattern, except that of hummocks and hollows, and by a relatively flat bottom. A portion of the Parker pool in Robinson county, Illinois (Fig. 1), is perhaps such an accumulation.

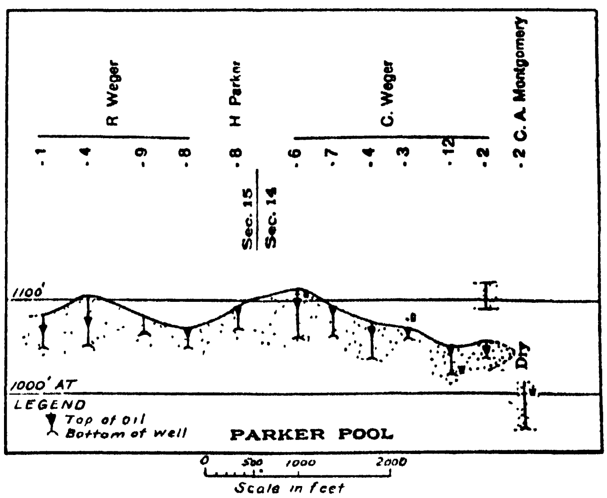

FIG. 1. A sand body whose cross-section suggests dune origin.

In continental deposits lenticular sands might represent river channels, sand dunes, or the braided channels of broad alluvial fans.

Channel sands are more easily preserved than shoreline sand bars because only sinking is required to permit their burial and preservation. Thus, probably, they are much more common than lenticular sands of the off-shore bar type.

Examples of Oil-pools in Lenticular Sands

The literature on the detailed nature of the sand bodies serving as reservoirs for oil- and gas-pools in 'lenticular sands' is not extensive. Mention of lenticular sand is common, for such sands produce oil in many fields in all parts of the world, but only under rather exceptional conditions

can the sand bodies be traced sufficiently far by drilling to reveal their true nature and extent. On localized anticlinal structures where production is confined to the upper part of an anticline it is commonly easy to recognize that sands are lenticular, but the type of lenticularity often cannot be determined because drilling is stopped at the limits of the productive area, and consequently the sands are not followed out for their whole extent.

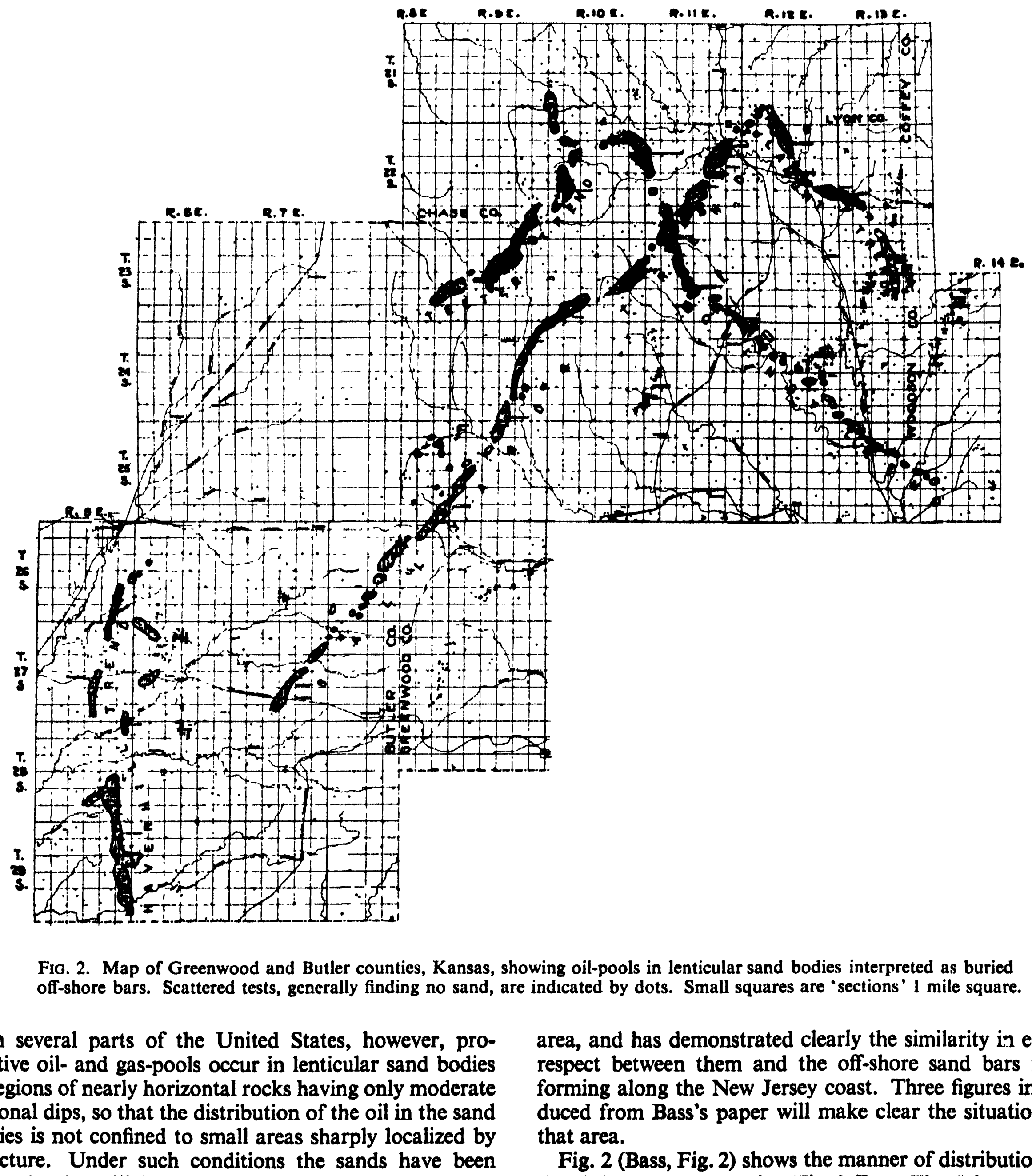

FIG. 2. Map of Greenwood and Butler counties, Kansas, showing oil-pools in lenticular sand bodies interpreted as buried off-shore bars. Scattered tests, generally finding no sand, are indicated by dots. Small squares are 'sections' 1 mile square.

In several parts of the United States, however, productive oil- and gas-pools occur in lenticular sand bodies in regions of nearly horizontal rocks having only moderate regional dips, so that the distribution of the oil in the sand bodies is not confined to small areas sharply localized by structure. Under such conditions the sands have been traced by the drill far enough for their form and pattern to be accurately determined from well logs.

Several such areas illustrating various types of lenticular sand bodies are described in the following section.

Off-shore Bar Sand Bodies in Eastern Kansas

In eastern Kansas, particularly in Greenwood county and parts of adjoining counties, are the best-known examples of buried off-shore sand bars serving as reservoirs for oil accumulation. On account of the richness of these pools and the fact that, over most of the county, oil occurs in the bar sands wherever they are found, drilling has been active, so that the shape and extent of the sand bodies has been determined in detail over a large area.

Bass [1, 1934] has recently made a thorough study of these sand bodies in the Greenwood and Butler county area, and has demonstrated clearly the similarity in every respect between them and the off-shore sand bars now forming along the New Jersey coast. Three figures introduced from Bass's paper will make clear the situation in that area.

Fig. 2 (Bass, Fig. 2) shows the manner of distribution of the oil-bearing sand bodies; Fig. 3 (Bass, Fig. 6) is a stereogram of the sand body of a typical sand-bar oil-pool about $3\frac{1}{2}$ miles long and 1 mile wide; and Fig. 4 (Bass, Fig. 10) shows a side-by-side comparison on the same scale between the buried sand bodies in the Pennsylvanian shale of Greenwood county and present sand bars along the New Jersey coast.

The salient features brought out by Bass's study are:

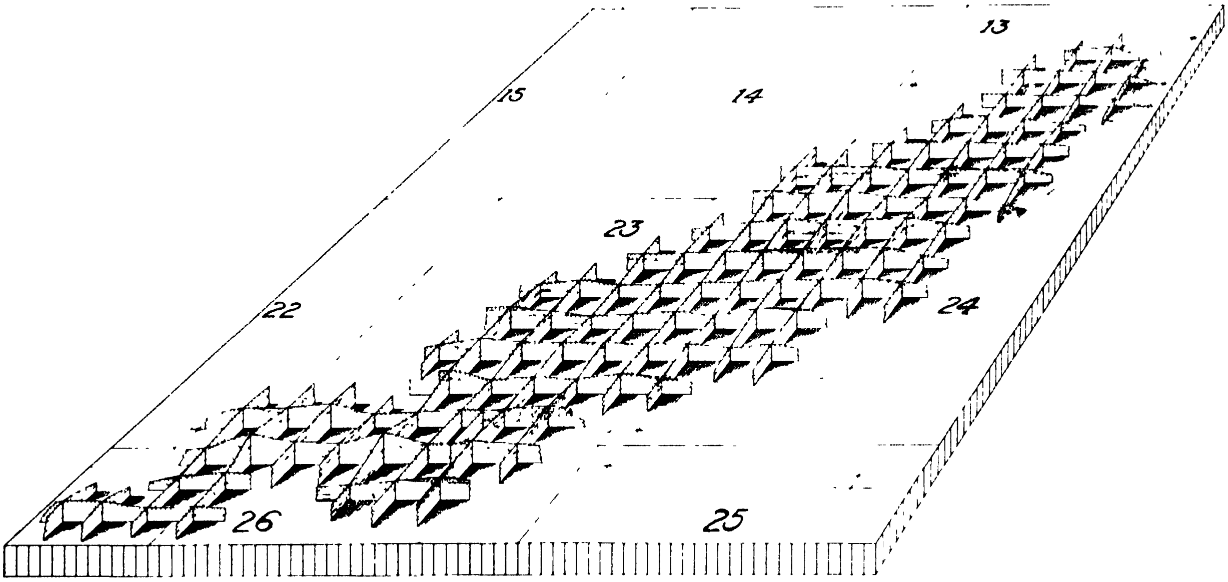

FIG. 3. Block diagram of Bartlesville sand body in Burkett oilfield (T. 23 S., R. 10 E., Greenwood Co., Kan.). Vertical lines at intersections represent wells. Dotted pattern represents Bartlesville sand. Dashed pattern represents shale at Bartlesville horizon. White band below sand represents underlying shale. Light line encircling diagram represents approximate boundary of sand body if projected. Sand body is 75 ft. thick in central part of field. Wells are spaced 660 ft. apart. Symbol represents dry holes. Section lines shown by dashed lines.

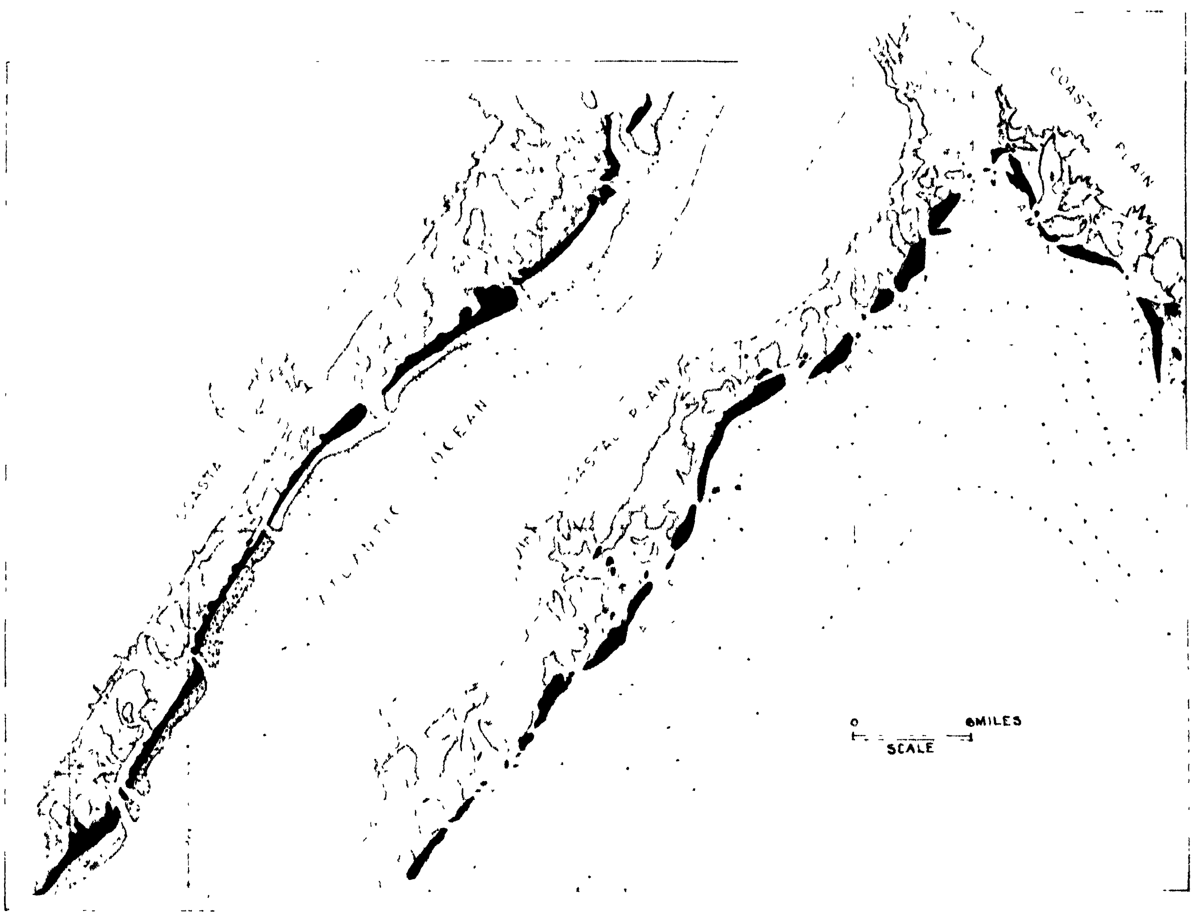

FIG. 4. Left: Sketch of part of New Jersey coast (After *U.S. Coast and Geodetic Survey Chart 1217*). Dotted-lined area represents Atlantic Ocean; solid black with adjacent stippled areas represents offshore bars, shaded area at left of bars represents lagoons with coastal plain farther left.

Right: Sketch of part of shoestring-sand area, Greenwood County, Kansas. Dotted lines represent Cherokee sea; solid black represents Bartlesville sand bodies; shaded areas represent lagoons. Squares are townships 6 miles square

(1) the distribution of the lenticular sand bodies in long, relatively straight 'trends', of which two sets are recognized. These are believed to mark successive positions of the strand line along the border of a shallow sea which underwent moderate tilting in the interval between the deposition of the two sets of bars; (2) the pod-like shape, and the discontinuity of the sand bodies within the 'trends'; (3) the offsetting of the individual sand bodies in the same manner as sand bars are offset along the present coasts; and (4) the characteristic shape of the sand bodies in cross-section. They thicken at the top and in the middle, and pinch out low at the edges in a fashion typical of sand bars, but quite different from channel deposits.

Channel Sand Bodies in Eastern Kansas

In the eastern counties of Kansas many oil-pools are found in long, narrow sand bodies which have been interpreted as channel fillings. These 'shoestring' oil-pools have been described by Rich [14, 1923; 15, 1926] and by Charles [6, 1927]. A map of an area near Garnett, Anderson county, where the channel sands are well developed, Fig. 5, shows that the sand bodies extend for many miles—in the case of the Bush City shoestring it is over 14 miles without a break—in broadly swinging curves. The sand thickness averages about 50 ft. in the central part of the channel, and the width varies from about 1,000 to 1,500 ft. A typical cross-section near the west end of the Bush City shoestring is shown in Fig. 6.

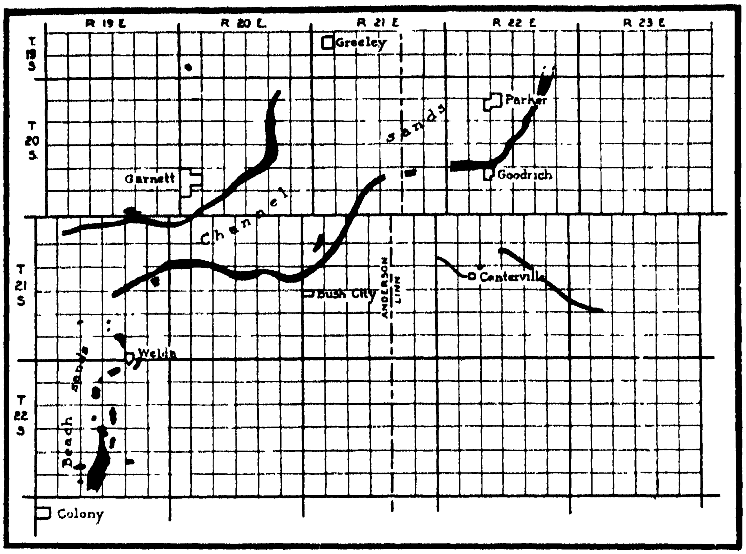

FIG. 5. Oil-pools in the 800-ft. or 'shoestring' sand of Anderson and Linn Counties, Kansas. The sand bodies fill ancient stream channels except at the south-west corner of the map where the streams seem to have emptied into open water and shore bars were formed. (*Base map, after Rich*)

The channel bottoms are nearly flat; the sides are abrupt; the tops are nearly flat, but may sag slightly in places; and thin bodies of sand occur at the edges of some of the channels at a level a little higher than the top of the main sand body. These are interpreted as former natural levees. The channels are cut sharply into marine shale of Cherokee age (Pennsylvanian).

Within the channels the porosity of the sand is variable. Parts are clean, relatively pure sand, and others are muddy. As a rule the sands tend to be cleaner and the channel bottoms a little deeper on the outsides of the bends. Outside the channels no sand is found except for the thin, natural-levee sand that is sometimes found close to the channel as already described.

An analysis of the possible origins of these channels leads to the conclusion that they were formed by consequent streams which cut into a flat, slightly raised, coastal plain resulting from moderate temporary withdrawal of the Cherokee sea. Lamination of the sand, as revealed

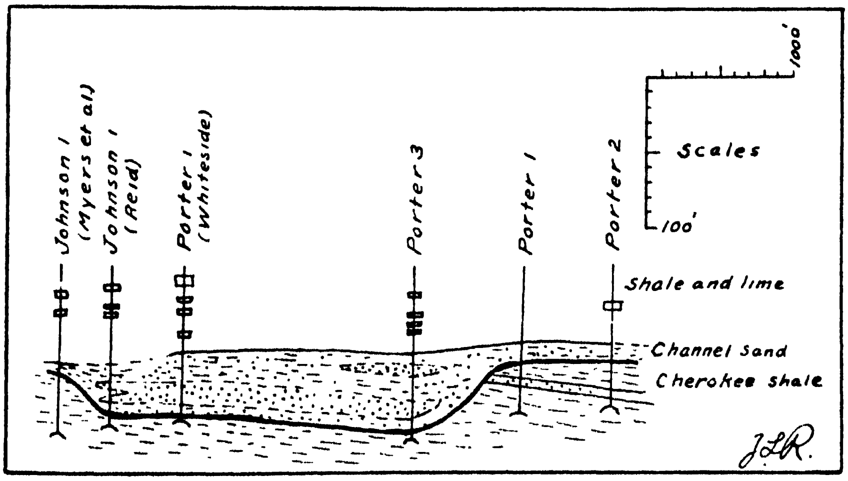

FIG. 6. Cross-section of Bush City channel sand body, Sec. 13, T. 21 S., R. 19 E., Anderson Co., Kansas. Shows sand-filled channel cut sharply into Cherokee shales, also irregular distribution of sand and sandy shale within the channel.

by drill cores, is of a type suggesting deposition under conditions of ebb and flow, indicating that at the time the channels were being silted up their water was subject to the tides.

At least two instances have been recognized in Anderson county where channel sands merge into sand bodies of the beach type trending approximately at right angles to the channels, indicating that the streams emptied into bodies of open water where the sands were strung out along the shore.

Criteria for distinguishing between Buried Channels and Buried Sand Bars

In the paper on the shoestring sands of eastern Kansas (Rich [14, 1923]) and in the report on the Birds quadrangle of Illinois (Rich [13, 1916]) the author has given criteria for distinguishing between channel sands and sand bars. The channel sands are continuous and thicken at the bottom; the bar sands occur in lens-shaped patches along a more or less definite trend, and thicken at the top. The sand bodies of the bars are commonly unsymmetrical. Their tops are likely to slope down smoothly on the seaward side, but to be broken and extend out in fingers into the shale on the landward side (Fig. 7). Coal also has been found in several instances on the landward side, indicating contemporaneous filling of the lagoons behind the bars with vegetable matter.

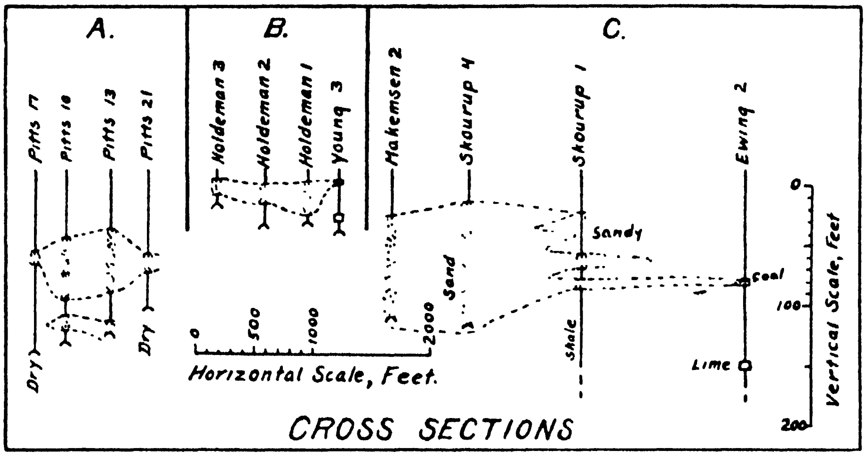

FIG. 7. Cross-sections of typical Kansas 'shoestring' sand bodies. Section *A*, Elmore shoestring, shows thickening at bottom indicating probable channel origin of the sand. Section *B*, Sec. 15 and 16, T. 23 S., R. 18 E. A typical channel sand body. Note thickening at bottom. Section *C*, east side of Colony sand body at Colony, Kansas. Shows thickening at top and also fingering and coal on eastern (lagoonward?) side. These features suggest that the sand body is a buried off-shore bar.

Tidal Inlet Channels in Eastern Kansas

What are believed to be tidal inlet channels have been recognized in the Greenwood county area of Kansas already mentioned. The cross-section of one of the clearest of these is shown in Fig. 8, taken diagonally across what is believed to have been a tidal inlet at the south-eastern end of one of the sand-bar oil-pools shown on Bass's map, Fig. 2. At the left in the cross-section are the convex-topped bar sand body, and at the right the flat-topped channel type of sand body at a lower elevation which is believed to represent the filling of a tidal channel between two bars.

Lenticular Sands in the Illinois Oilfields

Much of the oil produced from the Pennsylvanian formations in the Illinois oilfields comes from lenticular sands of one or another of the types mentioned. It was in connexion with a detailed study of that area (Rich [13, 1916]) that many of the principles used in the interpretation of the lenticular oil in sand reservoirs were first worked out.

The portion of the Illinois fields referred to lies on the broad, flat crest of the La Salle anticline in Crawford and Lawrence counties. On the larger regional structure the detailed distribution of the oil and gas in several of the productive sands is controlled almost entirely by the distribution of the sand bodies. In the report mentioned, the criteria used in differentiating various types of sand bodies are discussed and illustrated by cross-sections constructed from well logs. Sand bodies believed to represent shore bars, filled tidal inlets, and buried sand dunes were recognized.

Clinton Sands of Ohio

The so-called 'Clinton' sands of central Ohio have yielded a large amount of gas and some oil from the up-dip edge of a sedimentary wedge on the eastern flank of the broad Cincinnati arch (see J. R. Lockett [9, 1927]). Over part of the area production is from a sheet sand, but in other parts, especially in the northern half of the productive belt, the sand occurs in irregular lenses or patches several miles long and from a fraction of a mile to 2 or 3 miles wide (Fig. 9). Except, perhaps, along parts of their western margin, these lenses are not arranged in definite trends like the off-shore bar sands of Greenwood county, Kansas, described by Bass (loc. cit.). They are more irregular and the sands are generally much thinner than in the Kansas area. Nevertheless, the lenses show a decided parallelism in trend which is believed to correspond in direction with that of the shoreline, or at least with the axis of the embayment, at the time they were deposited. They show, therefore, the features which would be expected of sands of the sub-aqueous bar type. Further more detailed study will be required before the exact origin of these sands can be more definitely established.

Lenticular Sands in the Appalachian Fields and their relation to the Shoreline

Most of the oil in western Pennsylvania and in adjacent parts of Ohio and West Virginia occurs in irregular lenti-

cular bodies of sand or in patches or streaks of soft, porous sand within more widespread sheet sands. (See U.S. Geological Survey, folios, nos. 121, 134, 144, 146, 176, 177, 178, and *Bulletins*, nos. 318, 354, and 356.) The oil occurs in the central part of the Appalachian geosyncline at or near the western limits of the various sands where they become thin and patchy before pinching out into shale. Towards the east the same sands thicken and become coarser towards their source in the old Appalachian land mass. In the oil-producing area all the sands, except, perhaps, the the pattern would, of course, be much simpler, and from it some idea might be had of the conditions of deposition when that particular sand was laid down.

In order to bring out the pattern for one sand, the accompanying map, Fig. 11, of the oil- and gas-pools in the 'Hundred-foot sand' was compiled from the folio maps. The pools are superimposed on the structure map so as to bring out to what extent they are dependent on structure and to what extent on sand distribution. In the 'Hundred-foot' sand in that area the oil and gas accumula-

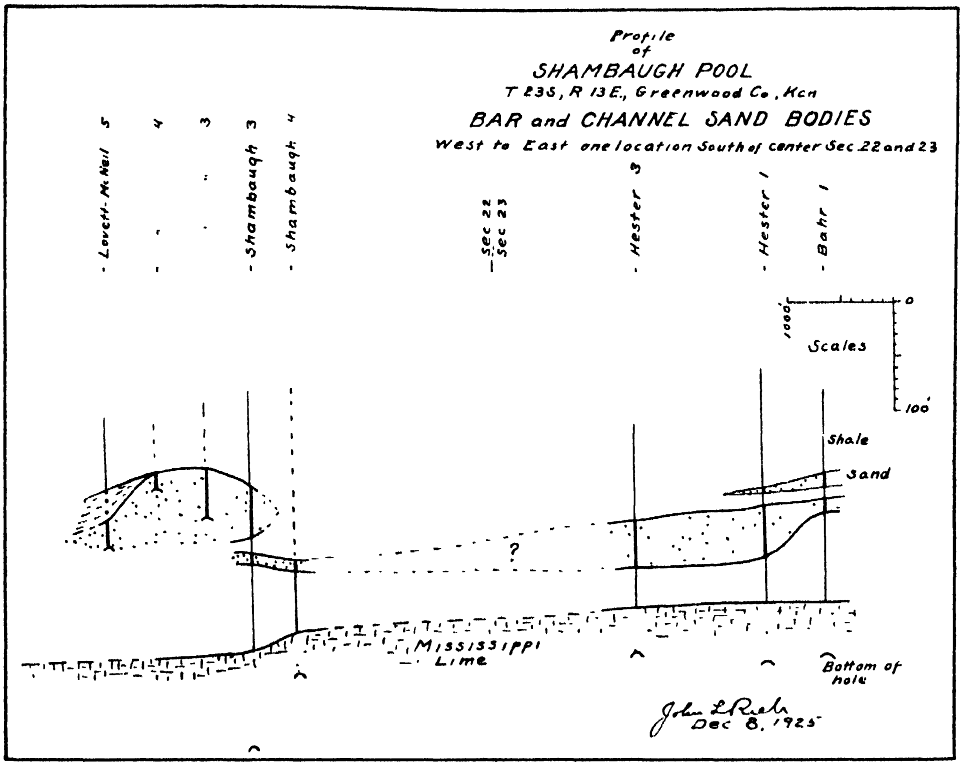

FIG. 8. Cross-section showing an off-shore sand body at the left associated with a sand body of the channel type which is believed to represent a partly filled tidal inlet between sand bars. Greenwood county, Kansas.

upper ones of Pennsylvanian age, are marine. They seem to have been deposited in the open water of an embayment formed by the sinking of the Appalachian geosyncline between the Cincinnati arch on the west and the Atlantic highland on the east.

In general, and for most of the sands, the evidence indicates that the belt where the sands become patchy in distribution or in porosity marked their farthest extension seawards, and that their lenticularity was probably caused by the actions of currents following the Appalachian embayment, more or less parallel to the general shoreline.

The Berea sand, however, higher in the section than the Devonian sands forming most of the pools, thins out to the east, suggesting that it was derived from the western side of the trough. Details of shape and pattern of certain of the Devonian sand bodies suggest that some of them, also, were deposited along the west side of the embayment, but the evidence is not conclusive.

The pattern of distribution of the oil-pools of the Appalachian fields, and their relation to the major folds of the region, are well shown on the accompanying map of western Pennsylvania, Fig. 10, but in reading this map it must be borne in mind that oil- and gas-pools at several different horizons are superimposed. For any one horizon tions are controlled mainly by streaks of porous, conglomeratic sand in a thick and widespread sand body, though some of the pools seem to be at the western margin of the sand where it pinches out into shale.

Neither the pattern of the Appalachian pools as a whole nor that of the pools in the 'Hundred-foot' sand suggests deposition as off-shore bars such as have been described in Greenwood county, Kansas, or as channel sands. A distinct alinement is, however, visible, and on the map of the 'Hundred-foot' sand, Fig. 11, three fairly distinct 'trends' or lines of pools can be made out, though the individual oil-pools are quite irregular. Unfortunately for our purpose, the map shows only the outline of the oil and gas accumulations, and not necessarily the limits of the porous sand streaks, which may or may not be similar. For the most part, however, the published discussions of the area indicate a fairly close correspondence between the outlines of the pools and the extent of the porous sand streaks.

It seems certain that these sand trends do not represent the actual shoreline, especially in the 'Hundred-foot' sand area shown in Fig. 11, for they are merely especially porous streaks in a widespread sand. They are believed to represent the results of assortment and strewing of coarser

material along the sea bottom by currents, but it is possible that the water was shallow enough for wave action during exceptional storms to have affected the bottom and to have been in part responsible for the 'trends'.

Neither of the pattern maps of the Appalachian pools, Fig. 10 or Fig. 11, reveals any close relation between production and structure. All geologists who have reported on the region agree that the distribution of porosity of the sands has had more influence than structure in determining the location of the oil- and gas-pools.

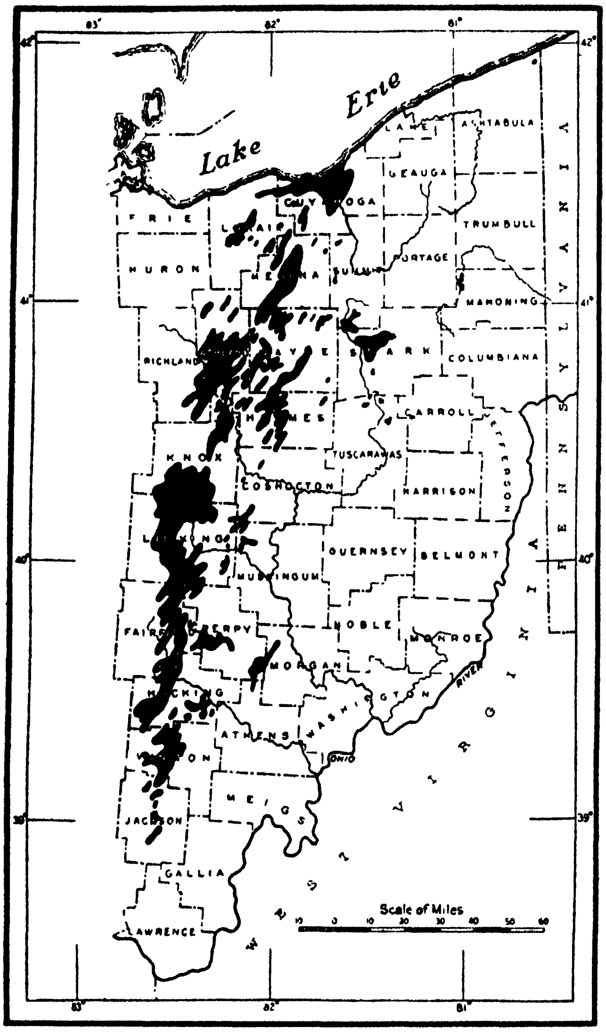

FIG. 9. The 'Clinton sand' fields of eastern Ohio. These fields occur along the up-dip edge of the 'Clinton' sand where it becomes lenticular before pinching out into shale to the west. *(Map by J. R. Lockett)*

In detail, within the limits of any one of the porous areas, structure undoubtedly plays a part. Gas may be in the highest part of a given lens, and water in the lowest, if both are present, but in many instances there is no water, and the oil is in the lowest places it could reach.

Jones [8, 1920] has pointed out the rather striking trend of the Appalachian oil- and gas-pools, approximately parallel to the general trend of the Appalachian geosyncline and presumably of the Appalachian shoreline, and the fact that these trends are not coincident with the structural axes. From these features and from the assumption that oil is derived from rich bituminous source materials and has not migrated far, he has argued that the 'present position and shape of the pools closely conforms to the underlying or overlying source of supply', which he believes to have been lagoonal areas close to and generally parallel with the coast line at the time of deposition, '. . . each line of pools corresponding to successive shore lines, with generally barren belts intervening'.

Jones's observation that the trend of the pools has a depositional rather than a structural origin is certainly correct, but the correlation of the pools with strips of bituminous lagoonal sediments is open to question. A correlation with strips of porous, reservoir-making sediments seems more nearly to fit the facts, especially as the correlation between oil-pools and streaks of porosity in the sands has been made by most of the writers who have described those pools. Besides, the sands appear to be of the subaqueous bar rather than the off-shore bar type such as should have been associated with coastal lagoons.

Torrey [18, 1934] believes that the reason that the oil is found mainly in the western, thinning edges of the various sand horizons is that, there, the sands were deposited in quieter waters farther from shore and are interbedded with marine shales rich in organic matter, whereas eastwards, towards the shorelines, the shales between the sands become more sandy and contain less organic source material. Thus, according to Torrey's ideas, it is not the belt close to the shore that is most favourable for oil, but one farther out. Torrey argues against extensive migration of oil and against its generation by geodynamic agencies. Those questions do not concern us here except that the occurrence of oil in lenticular sand bodies is cited as an argument against migration.

How oil and gas may have found their way into the lenticular sands is a puzzling question which can only be touched upon here.

Migration and Accumulation of Oil in Lenticular Sands

The common occurrence of oil in lenticular sands is often cited as proof that oil is formed essentially in place and does not migrate laterally into its reservoirs.

If a sand lens is entirely surrounded by impervious shale not broken by any joints or other fissures, it is conceivable that oil could be squeezed up or down into it from the adjacent shales as they are compacted, but lateral migration to the sand of the lens from any considerable distance seems out of the question.

Yet certain facts of distribution of oil and gas in lenticular sands suggest so strongly that extensive migration has occurred that we seem justified in questioning the assumption of complete isolation of the sand lenses.

The strongest evidence indicating extensive migration to the lenticular sand reservoirs is that in many regions the accumulations of oil in lenticular sands are on regional 'highs' where they would be expected if the oil had been free to migrate. As examples may be cited the pools on the Bend arch of Texas; the Greenwood county shoestring pools of Kansas; the lenticular sand pools of the Illinois oilfields; and the 'Clinton' sand-pools of Ohio—the latter on the up-dip side of a pinching sand body.

If the oil has not migrated into these lenticular sand-pools, why should they be found in places that are so situated structurally that oil would have migrated to them if it had been free to do so? In the case of the Greenwood county shoestring pools the evidence seems especially strong, for the accumulations are in an area that was regionally high during the Pennsylvanian and Permian

periods when the oil is believed to have accumulated (Rich [17, 1933, p. 804]). In the regionally high areas most of the sand lenses are entirely filled with oil, though a few miles to the north, off the 'high', similar sand bodies occur at the same horizon, but are filled with water instead of oil.

Two possible ways in which oil might migrate to the lenticular sands and accumulate in them under the control of structure may be suggested. One is that the sand bodies may be more effectively connected with each other underground than we suspect; and the other is that oil may migrate to the regionally high areas through continuous porous 'carrier beds' lower in the section and then find its way up through fissures to the lenticular sands (Rich [16, 1931]).

The discovery by Price [12, 1935] that the nature of the waters in the shallow lenticular sands of the Corpus Christi region of Texas indicates relatively free intercommunication between sand lenses, suggests that, at least in the early stages of burial, the sand lenses may not be so thoroughly isolated as has commonly been supposed.

An interesting relation noted in some of the oil- and gas-pools in the 'Hundred-foot' sand of Pennsylvania is that one sand lens may contain only gas while an adjacent one contains only oil. This condition is well shown on the oil and gas map of the Burgettstown-Carnegie folio, no. 177. Although the subject has not been specifically discussed in the reports on that area, it seems reasonably certain from the maps that the condition is fairly common. One may well ask why one sand lens should be entirely filled with gas while another, near by, is filled with oil to the apparent exclusion of gas. One possible explanation is suggested below, tending to bear out the idea that oil and gas utilize fissures for their migration to a greater extent than has generally been realized.

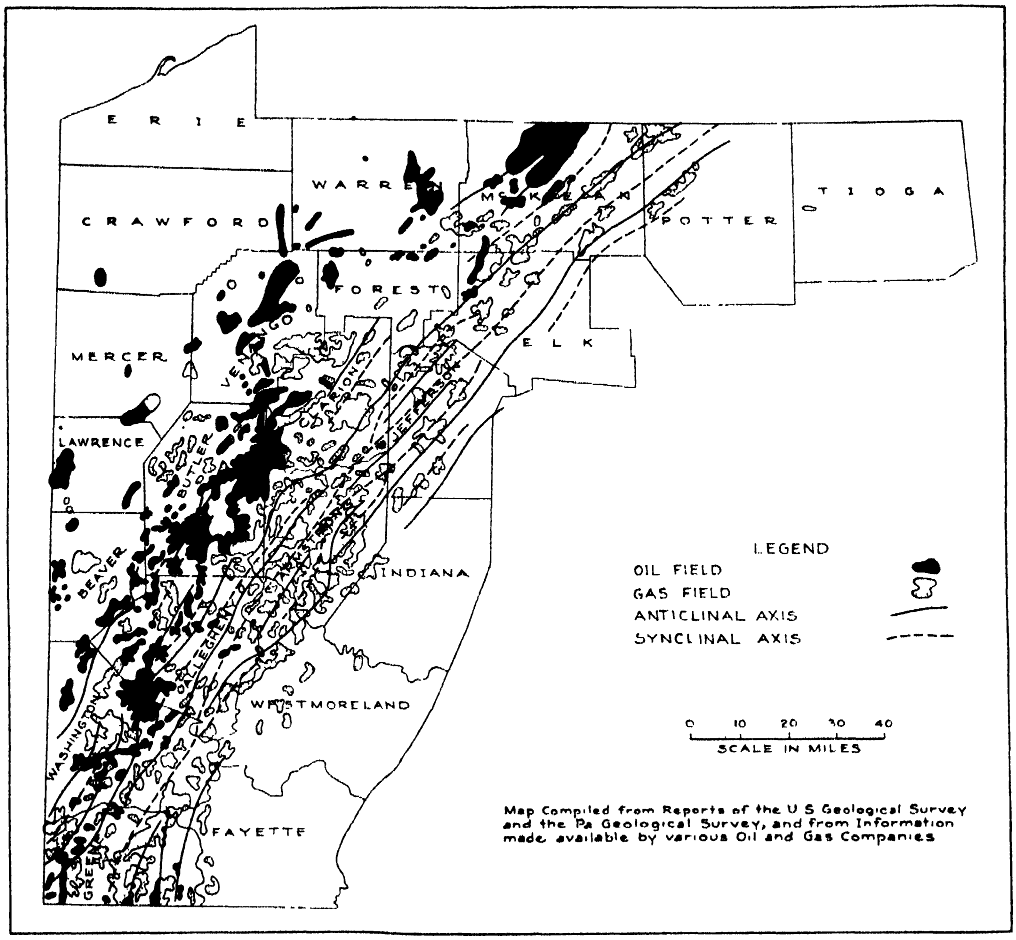

FIG. 10. Map showing oil- and gasfields and principal structural axes in western Pennsylvania. (*Map by Paul D. Torrey*)

Mills and Wells [10, 1919] have given good reason for thinking that gas in large quantities has at some time escaped from the oil- and gas-bearing regions of Pennsylvania and has carried with it so much water-vapour that some of the sands have been almost completely desiccated, and in the remainder the water has been so reduced by evaporation into the escaping gas that it has been changed into a concentrated brine.

If we grant that at some time, perhaps soon after the deposition of the rocks, large quantities of gas moved through them, carrying with it or driving before it more or less oil, as Mills has shown it will do, we have a mechanism capable of filling some of the lenses of sand entirely with oil, while others near by and at the same horizon are filled only with gas, for if we conceive of one lens being tight, so that there is little passage of gas through it, that lens would presumably fill completely with gas at an early stage and would now contain only gas. If the seal over another nearby lens were broken by joints or fissures, or for any other reason was imperfect, that lens might well serve as a channel for the passage of gas and its entrained oil. If conditions were just right, the oil might be differentially

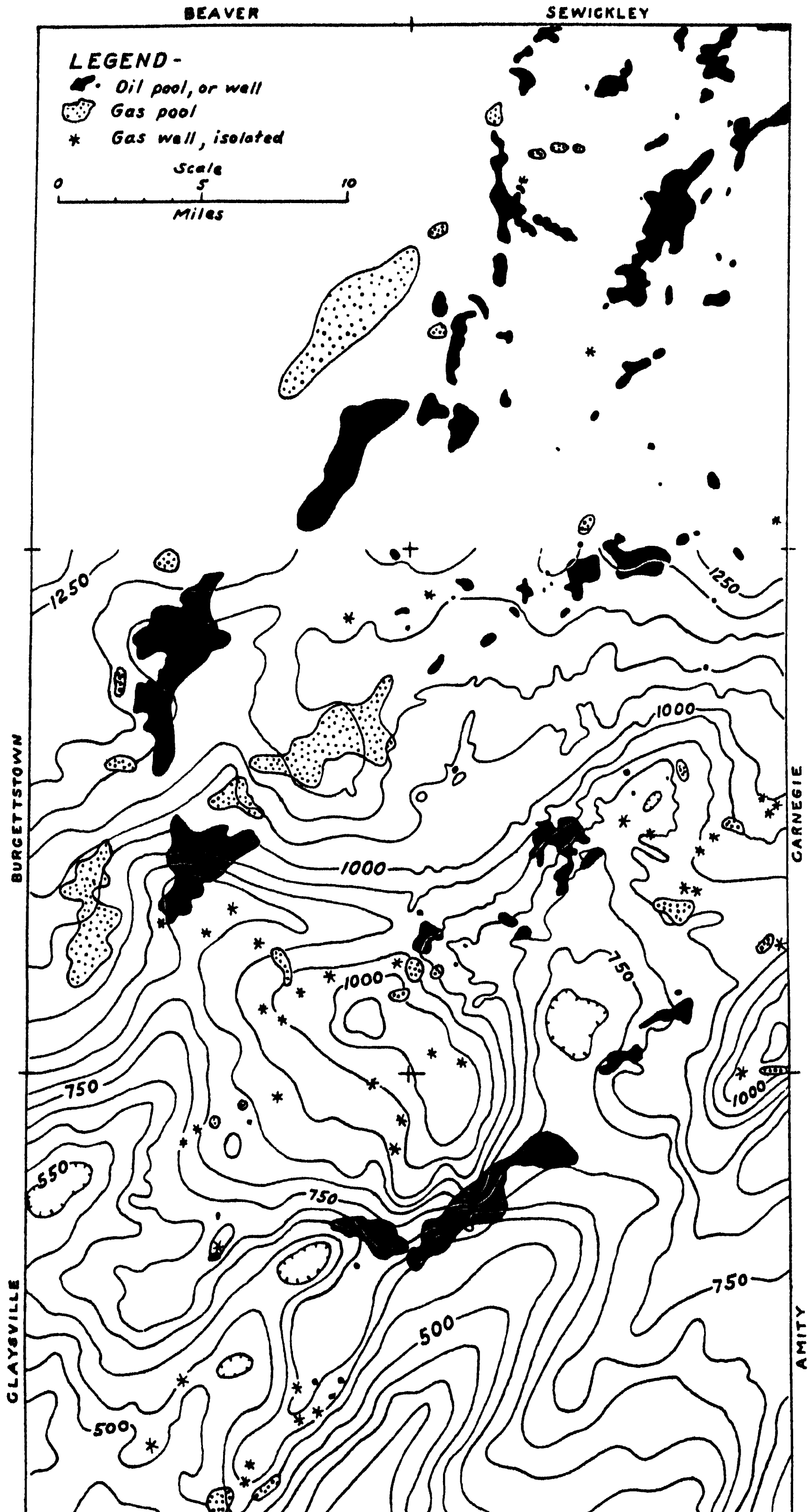

FIG. 11. Oil- and gas-pools in the 'Hundred foot' sand and structure of part of western Pennsylvania. Note rude alinement of pools irrespective of structure. Compiled from folio maps of U.S. Geological Survey.

screened out, while the gas, being able to escape through smaller openings than the oil, continued on its way. Thus a large accumulation of oil without free gas might be formed. Mills reports (oral communication) that in experiments conducted at the Bureau of Mines gas often broke through and escaped, leaving the oil behind.

Tracing Lenticular Sand Bodies

Applications of the principles of physiography can contribute much to aid a geologist in tracing lenticular sand bodies.

The first step is to determine, either by pattern or cross-section, the type of sand body. If it is a channel filling, the sand body may be expected to be continuous, of approximately uniform width, and to curve first in one direction and then in the other after the fashion of a meandering stream. The curves may be very broad and open, however, for such curves are characteristic of delta distributaries—a type of channel commonly to be expected.

If the sand body is of the off-shore bar type, it may be expected to be pod-shaped—tapering at the ends—and the units of a series of such sand bodies strung out in a 'trend' along the old shoreline may be expected to be separated from each other by barren areas representing tidal inlets between bars. Individual bars are likely to be offset somewhat *en échelon*, and may have hooks pointing lagoonwards at the ends.

If one is dealing with sub-aqueous bars formed of sand strewn along the ocean bottom by tidal or other currents, the problem is not so simple. The sand bodies may be thinner and are likely to be more irregular in pattern than the channel or shore-bar sands. General trends, or prevailing directions of elongation of sand lenses, may, perhaps, be recognized.

Finally, whatever the nature of the lenticular sand bodies, the relationship of oil or gas production in them to local structures must be ascertained. In some regions the lenticular sands carry gas or oil where they cross local 'highs' and water in the 'lows'; in other regions, as in eastern parts of Kansas, oil may be found in the lowest parts of the lenses, while gas or dry sand is in the 'highs'.

For best results in tracing lenticular sand bodies, an intimate knowledge of the local conditions, both structural and palaeogeographic, is essential.

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THE RELATIONSHIP OF BURIED HILLS TO PETROLEUM ACCUMULATION

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Introduction

AFTER 75 years of intensive development of the world's petroleum resources, the search for undiscovered oil-pools is still strongly guided by precedent. Cautious advances in development are made from conditions under which oil is known to be commercially available towards those conditions where the results are more problematical. The pioneer tests have been made adjacent to well-defined seepages, with subsequent extension of development as new precedents and methods are developed, to the more obscure indications of accumulation. Among the most obscure of the indications are buried hills, which by themselves or through their influence create one of the most important groups of petroleum reserves.

Up to the present, buried hills have been very little exploited throughout the world, due largely to the cautious manner in which the search for petroleum under new conditions progresses.

This hesitancy arises most particularly from the lack of *direct* evidence of the presence of oil-pools, but also from the vague knowledge of the principles governing the origin and accumulation of petroleum.

Each new productive province has its own problems of accumulation which can, as yet, be solved only by the development of new precedents based on trial and error, or the adaptation of certain precedents from other provinces. Those provinces which have the most obvious indirect indications, such as oil seepages and gas blow-outs, have received the earliest development with later activity, on less obvious indications, depending on diverse factors. In certain provinces, such as the Caspian area, Burma, Dutch East Indies, and Venezuela, in which strong seepages or simple anticlines in unconsolidated sediments indicated large accumulations of oil, development of the resultant oilfields has been adequate to care for the market requirements, and search for more complex producing conditions has been retarded. In areas like the Golden Lane of Mexico and the San Joaquin Valley of California, exhaustion of pools resulting from testing of seepages has forced the search into areas where more obscure indications of oil accumulations have resulted in the development of new reserves. Certain provinces were found early in the search for oil to have such highly developed anticlinal structure in their surface beds that the development sequence began with exploitation of these indications, and has not yet extended far beyond them. The principal examples of this type are found along the salt structures of Roumania and Germany, and the canoe-folds of Pennsylvania. Many other areas in which petroleum reserves have not yet been established may well ascribe this to the lack of obvious indications of oil accumulations. At a later date less obvious indications will reveal commercial oil-pools in certain of these provinces.

Of the major producing areas of the world, the central portion of the United States is the only one which, through a fortuitous coincidence of geological and accumulative conditions, geographical situation, and market demand has been able to follow the development sequence through in more or less orderly fashion. Starting with the discovery of oil-pools near seepage oil indications in south-eastern Kansas in 1889 and at Corsicana, Texas, in 1896, development spread to simple surface anticlines and other obvious indications. As these more easily evaluated features approached exhaustion, the search for more obscure indications was directed towards buried hills. This new field for investigation was sponsored by Sidney Powers in two papers published in 1917, 'Granite in Kansas', *Amer. Journ. Science*, 4th ser., **44,** 146–50 (1917), and 'The Healdton Oil Field', *Economic Geology*, **12,** 594–606 (1917), following the discovery of granite hills underlying the production along the Eldorado line of folding in Kansas, and of Ordovician hills underlying the Pennsylvanian sand production at Healdton, Oklahoma.

Following his conception of the importance of buried features, the area from the Rocky Mountains to the Mississippi River and from Nebraska to the Gulf of Mexico is being intensively prospected with core-drill, microscopic studies, geophysics, and the drill in search of buried hills, which will yield sufficient oil to take care of the ever-increasing demands upon the area.

Buried Hills

Buried hills, as broadly interpreted by American petroleum geologists, are either remnants of elevated topography or unroofed anticlines, against and over which younger sediments have been deposited unconformably, with or without contemporaneous arching. These buried features, then, fall into two groups—buried topography and buried structure—each having distinctive characteristics and exerting typical influence on the accumulations of petroleum associated with it.

Border-line cases inevitably arise between the two groups, due to their common origin in local upwarping. The buried topography group was either so highly folded or so deeply eroded following uplift that the importance of the original anticline was lost as far as oil accumulation is concerned, and the group remains important because of the influence of its topography. The buried structure group, on the other hand, was folded and eroded in such a manner that the oil accumulation in the original anticlinal structure is still present in large part, and is the dominant petroleum accumulation of the buried feature. Such pools as the Golden Lane of Mexico, Hurghada Oilfield of Egypt, Garber and Tonkawa in Oklahoma, are definite border-line cases, in that accumulation is found in the buried anticlines, but is also closely associated with the unconformity surface.

Buried Topography

Of the two groups of buried hills, buried topography was first recognized as a distinctive influence on petroleum accumulation. In Kansas, intensive drilling in Eldorado, Augusta, and smaller oilfields showed clearly that following the Early Pennsylvanian upwarping of the basement granite and overlying pre-Pennsylvanian formations in the

Nemaha Ridge, there was long erosion with the removal of much of the sedimentary section from the crest of the ridge, leaving rounded granite knobs exposed at some places.

Subsequent broad submergence brought a long period of Pennsylvanian deposition, with sediments gradually filling in along the flanks of the ridge and finally covering it entirely. During the regional settling, however, there was continual upwarping of smaller amounts along the old line of weakness which had produced the Nemaha Ridge. This movement, together with the greater compaction under increasing load of the thicker prisms of sediments on the flanks, maintained anticlinal structure over the buried ridge during much of the period of Pennsylvanian and Permian monadnock during the deposition of the younger formations.

These superposed anticlines frequently cover a large area and have produced large quantities of oil and gas. The oilfields of Eldorado, Augusta, and Oxford, Kansas; Braman, Thomas, and Garber in Oklahoma, along the Nemaha Ridge; and the world's largest gasfield in the Panhandle of Texas, are striking examples (see Fig. 1).

The sealing of sands deposited on the flanks of the buried ridge is of less importance, due to the generally erratic character of the production. However, part of the 'granite wash' oil production of the Texas Panhandle is of this type.

Secondary porosity developed in the surface of the high topography by weathering and erosion prior to its covering

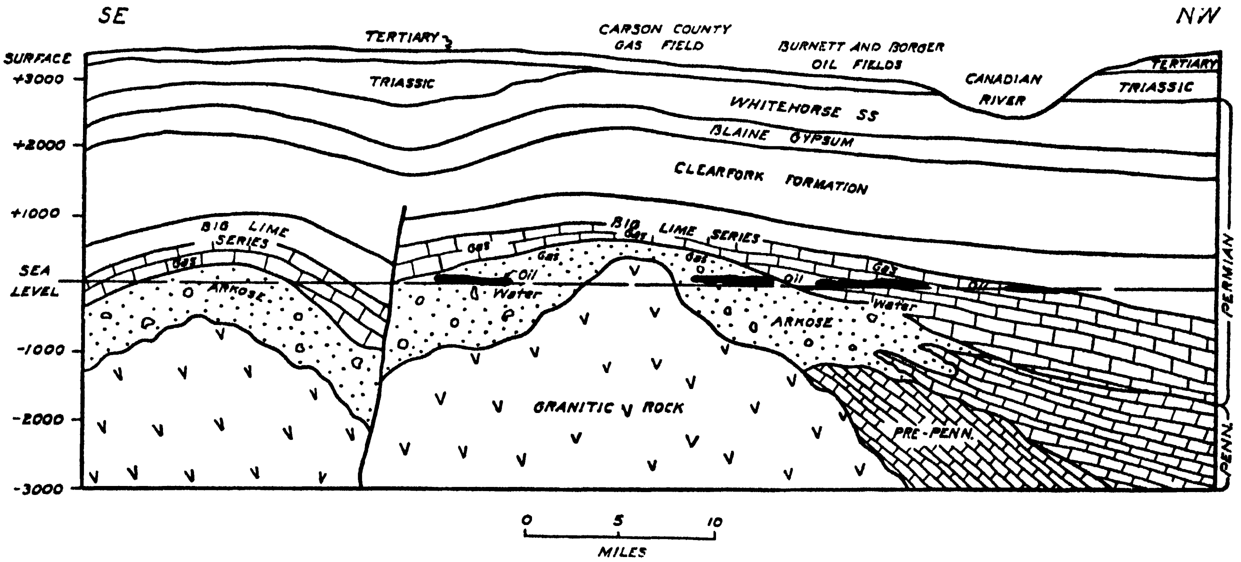

FIG. 1. Cross-section of the Panhandle buried ridge, Carson-Hutchinson Counties, Texas. Reflected buried topography, with oil and gas accumulations in the superposed anticline, in dolomites of the 'Big Lime' series and arkosic sands. Flanking arkosic sands are also productive.

deposition, beyond which time information is lacking. Later regional upwarping, which brought the area above sea-level finally, was again locally intensified along the buried ridge, leaving a pronounced surface anticline in the Permian rocks overlying the crest of the ancient granite ridge very closely. This Nemaha axis is a typical reflected buried hill, and its history corresponds very closely with that of many other similar features, such as Healdton and Hewitt, Oklahoma, the Panhandle fields of Texas, Sweet Grass Arch in Montana, and the Gebel Zut Oilfield in Egypt.

The Healdton field of southern Oklahoma differs from oilfields along the Nemaha Ridge in that the pre-existing island around and over which the present oil-producing formations were deposited was a highly folded complex of Ordovician sediments. In both cases, however, the topographical feature and its influence on the adjacent sediments were the important factors in petroleum accumulation.

Buried hills of the high topography group gain their importance by arching up sands deposited over their crests, by contributing in varying amounts to the petroleum recovered from adjacent beds, by providing reservoirs in their highly weathered buried surfaces, and by sealing off monoclinal sands deposited on their flanks. The most important of these functions is the anticlinal structure produced in overlying oil-bearing formations through compaction of the sediments and by upward movement of the buried by younger sediments is of considerable importance, where exceptional porosity has been developed in limestone hills. The enormous production of such wells as the Potrero No. 4, Casiano No. 7, and Cerro Azul No. 4 of the Golden Lane of Mexico, which have averaged better than 90,000,000 barrels each from the weathered El Abra limestone, give an idea of the possibilities of this accumulation. Gas and oil are found in smaller quantities in the weathered granite core of the Panhandle Ridge in Texas.

Finally, minor amounts of oil may be yielded to flanking and superposed sands by oil-bearing sedimentaries which have not lost all their oil content during the high folding and denudation prior to the deposition of the covering sediments.

In general, the influence of buried topographical highs on accumulation of oil and gas is of less importance than that of buried structure, though several prolific oil- and gasfields have been found in the Mid-Continent area of the United States on this type of structure.

Buried Structure

The buried hills of the second group are buried unroofed anticlines which may have existed as low topographical highs at the time of submergence, but which find their importance as centres of oil accumulation mainly through their original anticlinal structure. The earliest structure of this type which received prominence was the Cushing anticline in

Creek County, Oklahoma, one of the large oil-producing folds, which was an unroofed pre-Pennsylvanian anticline with the Simpson formation (Ordovician) exposed on the crest. This fold was submerged in Middle Pennsylvanian times during regional sinking, but local upwarping during this movement developed the overlying anticlinal structure. Production on this structure was found in the buried Ordovician anticline after the superposed anticline in the Pennsylvanian had also been found to be highly prolific.

Buried structures may be reflected in the surface beds, as at Cushing, or they may be entirely concealed by later serves of petroleum made available. The Permian Basin folds of West Texas and New Mexico; Van in East Texas; Marshall, Lucien, and Covington in Oklahoma; Voshell and Burrton in Kansas; 'Tamasopo' Ridge in Mexico; Maidan-I-Naftun in Persia; and Gemsah in Egypt are highly productive unreflected buried structures. Big Lake, Reagan County, Texas, is a striking example of a twice-buried structure, for it produces from an Ordovician anticline which is unrevealed by the overlying Pennsylvanian and Permian beds and from the Permian anticline which is unrevealed by the overlying Cretaceous beds, the two

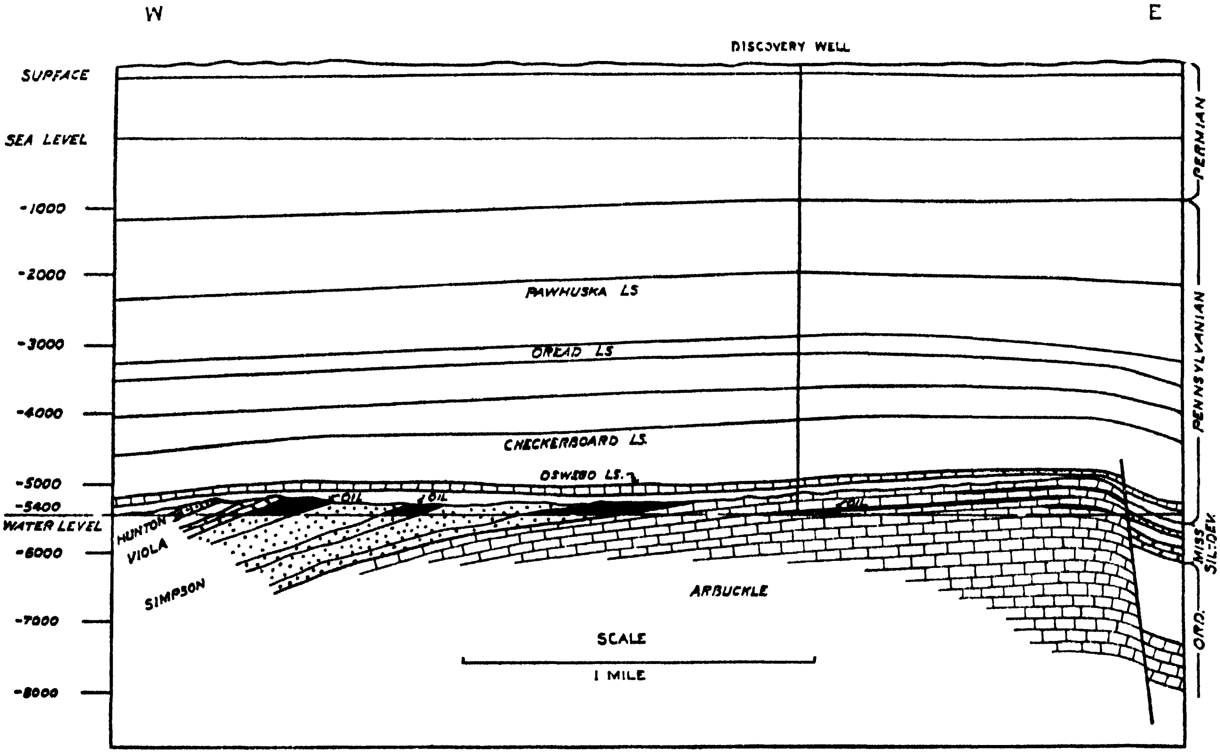

FIG. 2. Cross-section of the Oklahoma City field, Oklahoma County, Oklahoma. A reflected buried faulted anticline, with oil and gas accumulations in porous members of the Arbuckle limestone several hundred feet below the unconformity, in truncated sandstone members of the Simpson formation at the unconformity, and in anticlinal Pennsylvanian sands above the unconformity.

deposition during which there was no recognizable rejuvenation along the old lines of weakness, as at Seminole City, Oklahoma.

Many reflected buried structures, through the recognition of a low anticline at the surface, were tested and revealed early in the search for petroleum accumulations in the Mid-Continental United States. Such fields at Tonkawa, Garber, Yale, Oklahoma City, in Oklahoma; Fairport, Gorham in Kansas; Bend Arch and Yates in Texas, had ample surface expression to justify testing, and the discovery of oil in the reflected buried anticline resulted. Recently a more complicated surface structure was found to overlie the buried Ordovician fold at the Fitts Pool, Oklahoma. The inevitable testing of any suspicious surface structural indication led ultimately to the discovery of unreflected buried structures of the type found on the Seminole Plateau—such as Seminole City, Bowlegs, Little River, Earlsboro. These proved to be very prolific producers from the Ordovician, although their anticlinal nature was not indicated by similar structure in the Pennsylvanian beds on the surface. Through the advent of subsurface correlation, core-drilling, and geophysical instruments, further buried structures have been located and large re- producing areas overlapping but not coinciding in direction or location of apex.

Buried structures are important in the accumulation of petroleum largely through the anticlinal structure of the buried fold. The oil, accumulated in porous strata under typical conditions, is available for production well below the unconformity. In Oklahoma and Kansas the formations generally found below such unconformities are sands in the Simpson formation or the Arbuckle dolomite, both of Ordovician age; while in West Texas and New Mexico they are dolomites of Permian age. In all instances the pre-unconformity horizon has much better porosity than the horizons above the unconformity.

In certain cases the erosion of the anticline has proceeded far enough to uncover the oil zone before the submergence. In such cases the oil will migrate, at least in part, into the superjacent beds, and permit secondary accumulation of important reserves above the unconformity.

Of lesser importance on reflected buried anticlines is the oil found in the induced anticlinal structure in younger beds above the unconformity, although excellent production has been secured from such superposed anticlines in many fields.

An excellent example of a reflected buried anticline is the Oklahoma City pool in Oklahoma (Fig. 2). This pool yields oil in large quantities from porous horizons well within the Arbuckle limestone (Ordovician) core of the fold, as well as from the eroded Simpson sands on the flank, which have also supplied small quantities of oil to the debris material at the unconformity. Several sands in the Pennsylvanian section in the anticline above the unconformity have been tested for commercial oil and gas production, although these have not yet been developed, due to the greater yield of the Ordovician horizons. Such a structure producing from several different sources of accumulation makes a very prolific and valuable reserve.

Conclusion

In the present stage of world development, the central United States is the most important province in which large accumulations of petroleum have been developed in buried hills. These obscure features, which are to be found largely through greater zeal in exploration under the driving force of urgent demand, will be found more abundantly than at present suspected in many oil provinces which are still finding sufficient oil adjacent to the more obvious indications of accumulation. They remain, with unreflected buried salt-domes, the major unexploited reserve of the petroleum industry.

LOCATION OF OILFIELDS IN TECTONIC BELTS

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In a recent publication Professor Illing has shown that the regional distribution of oilfields is influenced by the following three factors:

(*a*) distribution of source-rocks,
(*b*) reservoir-rock conditions of accumulation,
(*c*) chances of preservation.

Distribution of Oil Facies

An examination of the petroliferous regions in the world shows that, almost without exception, these can be divided into two groups: fields located on the edge of mountain chains, and fields situated in subsidence basins. In these two groups the facies of the oil series change considerably; with the exception of continental facies, oil accumulation is encountered not only in purely marine deposits, but also in lagoonal or deltaic formations. Their sedimentary conditions are characterized by the enormous thickness of accumulated deposits, while in epi-continental seas and oceanic depths a reduced sedimentation took place during the same space of time This special type of facies is characteristic of subsidence basins. Subsidence by itself, a factor which must be considered in order to explain the thickness of deposits, fails, however, to account for the tremendous accumulation of detritic sediments, and the existence of an intense and continuous erosion in adjacent continental areas has to be admitted.

Such conditions are typically represented in the case of troughs in the foreland of mountain chains: the gradual rise of the chain is accompanied by a deepening of the foreland; at the same time active erosion has the effect of wear-down the rising mountains. Many oilfields are located in zones of this type. The case of subsidence basins is very similar to the previous ones, for in such cases tectonic phenomena, and especially isostatic readjustments take place.

As the result of the above-mentioned considerations a first point should be emphasized. There is a close relationship between the different features of tectonic zones and the distribution of oilfields. This connexion is only an indirect one, since shown by the facies of the deposits.

Role of Structure

A second factor to be taken into consideration is the direct influence of structure on the distribution of oilfields. The influence of general environments (large areas of uplift, synclinal basins, &c.) and of local features (anticlines, salt-domes, &c.) which have a local and definite influence on the distribution of the fields must be considered here.

In every case, however, stratigraphy and tectonics are so intricately related that it is absolutely impossible to separate these two factors. The influence of structure is not merely confined to the last periods of diastrophism. On the contrary, tectonic movements have taken place over long periods of time, and the deformation of the beds has been progressive. Consequently, *conditions of accumulation were not as they are to-day but have varied continuously.*

The distribution of oilfields at the present time should therefore be considered as the last term of a succession of varied stages of equilibrium. It should be necessary theoretically to take into consideration, in every case, another factor, time. Such a consideration is unfortunately impossible, but it is clearly involved, since oilfields correspond to different stages of evolution.

(*a*) **Unfolded Zones.** Subsidence basins of the type of the Gulf of Mexico show a series affected by a gentle dip towards the centre of the basin. The distribution of the fields seems at first sight erratic, but a closer study shows a concentration of oilfields in certain special areas. In the Gulf province the Sabine uplift, and in the Mid-Continent the Bend Arch, seem to have played an important role in the distribution of the fields. These features have probably not only a tectonic influence but also a stratigraphical one, through variations of the facies.

In these flat-lying series, the *oil is distributed in a great number of small structural irregularities*, and this type of accumulation may be considered as an older form.

By rotating the oil series through the angle of dip, until they lie in the horizontal plane, the small irregularities of the actual monoclinal surface appear as proceeding from elevations and depressions of the old depositional surface and oil accumulations correspond to the former. In some cases the sediments of the elevations are of a coarser type, which agrees with the studies of P. D. Trask on actual sediments.

These facts show the influence of this old depositional surface, which determines simultaneously the local facies and the distribution of the domes.

Where the continuity of the reservoir allows for migration, this type of deposit shows a remarkable instability. It can be supposed that, owing to tilting due to subsidence, deepening of the basin, or to erosion which will facilitate the motion of waters, a time comes when the previous state of equilibrium will be destroyed. *Oil will then migrate to more suitable 'traps'* and specially towards the higher regions of the reservoirs. Some barren structures in producing areas may be explained in this way.

Levorsen has previously emphasized the role of the tilting of the reservoirs in the secondary migration of oil. Such movement will vary with the nature of the reservoir, being a maximum in uniform deposits, and a minimum in the case of lenticular reservoirs. In the latter case, however, too strict an interpretation would prove to be erroneous. In many instances experience shows that ill-defined connexions may have existed between certain lenticular sandstones. For instance, the anticlinal disposition of many producing levels in certain small Carpathian fields, where the stratigraphy shows deposits of the 'flysch' type, is a definite proof. Wells drilled in synclinal zones have found insignificant traces of oil and salt-water only.

(*b*) **Folded Zones.** The 'embryonic folds' had the effect of remodelling progressively the monoclinal zones of the previous type. These folds have played an important role in the disturbance of a previous state of equilibrium and in the building of a new one. Through the tilting and folding of the reservoirs, as in the preceding type, the

closures will become insufficient for retaining the oil, which will *abandon its former zones of accumulation and migrate towards new locations on the folds.* The problem of eroded reservoirs is closely related to these facts. In many cases, where oil is not coming from beds overlying the reservoirs, subsequent accumulation of oil in the higher zones of the reservoirs may be due to folding. This folding has destroyed accumulations of the older type in zones which have not been eroded and permits a further migration of the oil into higher zones, eroded and covered subsequently by a transgressive cap.

(*c*) **Overthrust Zone.** The succession of orogenetic movements increase progressively the complexity of the structures, and their final stage results in overthrusts and nappes. Very few illustrations of fields of the last type are to be found, the chances of preservation becoming more and more precarious for oil. However, Canada, Poland, and North Africa have oilfields of such a type. The writer has been able to study the two last countries and gives here the result of his own observations.

Conditions of accumulation are extremely complex. Some structures, in spite of their regularity and their large drainage area, have proved to be entirely barren, whilst others, which would be condemned at first sight, on account of their unfavourable position and tectonics, have given production. These anomalies can be explained by a close examination of tectonic conditions.

A good illustration is given by the Boryslaw field in the Polish Carpathian Mountains. It corresponds to an axial rise of the frontal zone of a nappe. A few kilometres to the north-west a similar and even more important rise, at Nahujowice, is barren. A close study of the tectonics reveals that Boryslaw corresponds to an area of regional uplift where the different folds have been compressed against an elevation of the basement. The trend of their axis shows that this zone of compression, from which they escape to the north, forms a virgation.

The Nahujowice fold, on the contrary, has its origin in the depression and contains no oil. Its present rise is a secondary phenomenon due to the following factors. The fold, previously low, could advance freely, and at the same time rise on an inclined overthrust surface, but, during these tectonic movements, oil was already concentrated in the Boryslaw dome and remained there.

The same relationship exists between the Majdan and the Bitkow areas, the latter corresponding to an elevation of the basement, as proved by geophysical measurements.

In conclusion, it is possible to state that the present stage of oil accumulation results from a very complex evolution and is not only related to the present state of tectonics but had earlier and simpler stages. During the evolution, local readjustments naturally took place and resulted in a small accumulation of very light oil in the barren anticlines.

Destruction of Accumulations

The final distribution of oil is not only dependent upon the process of accumulation, but also upon the chances of preservation. This distribution is also modified by the destruction of some fields through erosion. The most radical process consists in the erosion of the reservoir which was very effective in every folded area.

Water circulation is another factor; a partial erosion of the reservoir permits the infiltration of surface waters and the flushing out of the oil. The Wyoming district offers typical illustrations of this phenomenon. Some seepages, which result in oil mixed with an enormous quantity of water being brought to the surface, may be due to a similar process, for instance Hit on the Euphrates River.

Finally, regional metamorphism will cause the disappearance of the hydrocarbon accumulations.

The Carbon Ratio Theory

As a conclusion to the present study, it is necessary to discuss briefly the 'carbon ratio theory', which offers an interesting solution to the problem of the distribution of oilfields.

Various observations have shown that in the Mid-Continent and in the Appalachians, oil accumulations are situated between certain isocarb contours. These isocarbs express equal proportions of fixed carbon in the coals of that area. The conclusion has been drawn that they are an index of the degree of regional metamorphism and especially of the point where oil first, then gas, would disappear. At first the carbon ratio theory was received with much favour by many scientists, but nowadays, owing to many contradictory facts, it is a matter of controversy.

The carbon ratio theory postulates:

> 'Coal beds are assumed to have the same original composition over their whole lateral extension, consequently every change in the composition of these beds is due to subsequent modifications in the environments, i.e. to regional metamorphism.'

Recent work on the composition of coals has given results which do not support the above-mentioned theory. In Europe observations made in the Franco-Belgian Coal Basin have shown that the variations in the percentage of fixed carbon in coals are essentially due to the nature of the detritals composing the different varieties of coals, which in turn are dependent on their position in the basin, i.e. on general conditions of sedimentation. Cuticle coals are found in the centre, whilst cellulose-lignin coals are deposited on the edges. To these factors must be added the effect of an early 'diagenetic process', representing the influence of environment on the carbonization phenomenon. The isocarb-contours, consequently, reflect the general sedimentary conditions.

American authors, on the other hand, hold contrary views. They consider that the composition of detritals is approximately constant for any given bed over the entire area of the basin. The absence of cuticles or of lignin or cellulose is due to their disappearance during the process of carbonization.

Recent studies made by Stadnichenko have shown that the increase of fixed carbon has no relation to the nature of the detritals. Duparque and White, starting from two different hypotheses, have shown the importance of an 'early diagenetic process' in the differentiation of the various types of coals. This diagenetic process is due to variations in the conditions in the different lagoons where the transformation of vegetable matter took place and is dependent on the degree of aeration of water which in turn is controlled by changes of depths and currents.

According to a prevalent opinion, the influence of regional metamorphism is not due entirely to temperature (below 160° C. no transformation is observed and it is necessary to reach 250° C. to obtain a transformation of about 2% in the proportion of carbon) but to pressure. In the Franco-Belgian Coal Basin observed facts are not in accord with this opinion: no relationship is found between faults, overthrusts, &c., and the trend of the isocarbs.

The above-mentioned considerations show how weak is

the basis of the carbon ratio theory. The isocarbs result, in the author's opinion, from three factors: grading of the vegetable detritus, diagenetic processes, regional metamorphism. The first two are sedimentary factors. The relation of the isocarbs to the regional distribution of oilfields may, therefore, be considered as expressing, first, the role of the sedimentary conditions and, secondly, the influence of regional metamorphism.

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OILFIELDS IN FOLDED ROCKS

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To a large extent, oilfields occur on gentle structures, in areas of comparatively very little folding. Such tabular regions are chiefly the 'forelands' of relatively more recent orogenetic zones. The tablelands themselves may have been subjected to earlier mountain building movements, but have become so solidified that they were not or only slightly affected by more recent movements. They formed the framework against which the later folds were directed.

Accumulations of petroleum are not only formed, but they are also frequently destroyed by subsequent geological events (cf. the article on the Stratigraphical Distribution of Petroleum). Within strongly folded mountain belts, the chances against preservation of oil deposits are very much greater than in relatively more quiet regions. For this reason oilfields are comparatively rare in strongly folded rocks. They are far more frequent in the foothills of the exterior zone of the chains, where folding is much reduced, or on the only gently warped tabular foreland. Other gentle structures often occur within depressions in the interior parts of mountain systems, which are filled by less disturbed later sediments. The reasons for the frequent destruction of oil deposits within strongly folded mountains are the following: (*a*) *erosion*, and (*b*) *dispersion.*

(*a*) Although high elevation is not necessarily the result of folding, which generally occurs at some depth in the crust, and mostly in submerged geosynclinal areas, a period of folding is usually succeeded by emergence and often even by strong regional elevation, during which erosion carves the highlands into a mountainous topography. The 'mountain building forces' may, therefore, primarily have been compressive folding, but the actual building of the mountains was strong regional uplift, followed by valley-cutting erosion. An enormous quantity of material is thus eroded and carried down by rivers and glaciers, first into valleys or interior depression basins, but afterwards spread as an extensive blanket over adjacent plains or sea bottom. The very basement of the interior chains is finally bared, denuded of its mantle of sedimentary rocks. Whatever deposits of petroleum may have been present in the latter are destroyed. For this reason oilfields are extremely rare in the heart of mountainous belts. Practically, they only occur within wide intramontane depressions, filled by a great thickness of sediments, which have merely been slightly affected by the later, less intense phases of the orogeny (the San Joaquin Valley and the Los Angelos Basin of California are good instances).

b. The violent dynamic thrust within the orogenetic zones, often accompanied by a downward buckling of the crust into considerable depths, and resultant injection of igneous rocks or mineralized solutions and vapours, cause chemical changes in the strata, which are called metamorphism. This may occur to a very variable degree. It may be so intense that the entire mineralogical aspect of the strata is profoundly changed. Even comparatively recent sediments can thus be transformed into crystalline rocks—schists, marbles, and quartzites—which cannot be distinguished petrographically from pre-Cambrian formations. In other cases metamorphism is so slight that silicates and other rock-building minerals are not visibly affected. We now know, however, that bitumina and coals are much more sensitive to chemical influence of this nature. The world's known oilfields all occur in unmetamorphosed or only slightly metamorphosed sedimentary rocks, but natural gas is found able to survive a somewhat greater alteration. Strongly metamorphosed rocks are barren of oil deposits. For the same reason source rocks could not remain in existence if depressed to depths exceeding 5 to 6 miles.

Where the strata affected contain coal-seams, these can effectively be used to indicate the amount of the very moderate metamorphism which is not strong enough to affect inorganic minerals. Slight metamorphism turns bituminous coals into harder varieties with less volatile constituents, and finally into anthracite. This is clearly demonstrated in the Appalachian coalfields of the eastern States of North America, where the gradual changes in the same seams of coal can be traced from the undisturbed foreland to within the heart of the mountains. The same process is, however, more or less clearly, in evidence all over the world. A map showing the regional carbon-ratio variations in Pennsylvania, Maryland, Virginia, West Virginia, eastern Ohio, and eastern Kentucky and adjacent regions, was published by David White and Ely in 1925 [1].

We now know that petroleum is affected in a very similar manner. The result is similar to the cracking processes used in petroleum refineries for the conversion of heavy oils into lighter varieties, chiefly gasoline, where the surplus carbon is left in the form of petroleum coke. In nature the effect of progressive regional dynamic alteration is also marked by a concentration of hydrogen in the distillates and a concentration of carbon in the residual debris. Metamorphism, consequently, lowers the specific gravity of the oils, so much that in the more strongly affected zones only gasfields remain and, finally, where metamorphism becomes more intense, no trace of oil or even gas is left, although general conditions remain equally favourable for the presence of oilfields. All this takes place within zones where there is not yet any trace of visible change in the rock-forming minerals of the sediments. Where coal is present in the oil-bearing section, as in the Appalachian oilfields, it can, therefore, sometimes be used effectively as a natural recorder of the local intensity of the metamorphic action to which the associated strata have been subjected, and the quality of coals can be used as an indicator for the position of the metamorphic 'dead-line', limiting the occurrence of commercial oil-pools. The contents of fixed carbon are used, as shown by proximate analyses of coals, calculated to the ash-free basis.

This so-called 'carbon ratio theory' is often used to estimate the promise of possible oil-occurrence in unprospected territory, but it has to be applied with circumspection; it has by no means such validity that a certain carbon ratio in some coal excludes all possibilities of finding commercial oil deposits in the vicinity. We are still less permitted to state that a certain degree of folding excludes the possibility for the preservation of oil deposits. Orogenic

pressure may have been relieved locally by the yielding of the beds in folds or faults, especially in overthrust zones. Metamorphism is not only a result of dynamic thrust, but also of temperature, arising from depth of burial. In an area of local and irregular thrusting, incompetent rocks, which have ridden passively on competent beds, or have been shielded from direct thrust by nearby faults, can be intercalated with other formations, which have been strongly compressed and more intensely metamorphosed. In this way patches of still oil-bearing strata may occur in checkerboard fashion between other areas with a high degree of alteration (for instance, oil seepage at Rose Hill, Virginia, and Stony Creek oilfield of New Brunswick). Accumulated geological observation, however, substantiates in a broad way that very strong folding, especially when found seriously to affect the carbon ratio of any coals present, adversely affects the chances of making important discoveries of oil within such areas as a consequence of the effect of local metamorphism.

That important oil provinces may occur in very intensely folded regions, within the overthrust front of major mountain systems, is illustrated in somewhat further detail by the following two examples: (1) the Turner Valley gas- and oilfield of Alberta, Canada, and (2) the Polish oilfields in front of the Carpathian Mountains (Boryslaw, &c.). Furthermore, a few remarks can be added on (3) the curious folding and upthrusting associated with saline formations (salt-anticlines and salt-domes), which often are connected with important oilfields.

1. **Turner Valley** is structurally probably the most complicated oilfield so far known in North America. It is a highly folded and faulted compound anticlinal overthrust sheet, bordering the outer foothills of the Canadian Rocky Mountains. It involves Palaeozoic limestones, dolomites, and shales, Jurassic shale, and Cretaceous rocks. The major overthrust fault, which underlies all of the structure, is of considerable magnitude and appears to have been subsequently warped. The thrustsheet is divided into a great number of individual slices. The adjoining cross-section, Fig. 1, perpendicular to the strike of the mountains, after T. A. Link and P. D. Moore [2, 1934], probably presents an essentially correct picture. The character of the overthrust structure is fully proven by 178 wells, notably by the McLeod No. 4 well (7,751 ft.), which reached the Cretaceous substratum, after having passed through the Palaeozoic, and demonstrated the tremendous drag on the underlying beds by the position of the Cretaceous *cardium* sandstone, inverted at the 6,300-ft. level, and in normal position at the 7,735-ft. level. In all cases, where cores were taken below the major thrustplane, high dips were observed to prevail in the strata. The warping of the thrustplane was proven by the varying elevations at which the fault was encountered in numerous wells.

Production is found in a dolomitized zone in the Palaeozoic limestone, which is generally found bituminous in places farther away from the mountains, and gives some oil-pools in the vicinity. Small amounts of oil and gas are obtained from Mesozoic sandstone at shallower depths.

As to the source of the oil, it is not improbable that the source rocks are in the Palaeozoic. In the Moose Mountain section, 20 miles north-west of Turner Valley, dark bituminous limestones and shales (Banff Shales) occur in the Lower Carboniferous. The Devonian is partly saliferous under the plains of southern Alberta (wells at McMurray on the Athabaska River), and has bituminous shales at the top. The Jurassic, which unconformably overlies the Palaeozoic, is confined to the Cordilleran geosyncline, and rapidly wedges out farther east; it is only thin at Turner Valley. It contains black bituminous shales of euxinic facies (cf. article on Stratigraphical Distribution of Petroleum). The Cretaceous is probably not an important source rock; the famous Lower Cretaceous subaerial tar sands on the Athabaska River are certainly no source beds and may have been impregnated either from the Devonian, or by tar washed into them from a remoter source (Cretaceous?).

As would be expected with dynamic forces of such intensity, the oil is a very light gravity naphtha (73·6 Bé. = 0·6899 sp. gr.), with large volumes of gas. Somewhat heavier oils are found in the younger formations and show a progressive decrease in specific gravity with depth. In the Kevin-Sunburst field, on the extremely gentle Sweetgrass Arch, on the Canadian border in Montana, the oil is found on the Jurassic-Palaeozoic contact, and in the same (Madison) limestone, and is 30 Bé. = 0·8762 sp. gr. To January 1934 the total production of the Turner Valley field has been 6·5 million barrels of naphtha and more than 600,000 million cu. ft. of gas.

For further details the reader may be referred to the cited paper by Link and Moore [2, 1934].

2. **The Polish Oil Province** is located in the frontal zones of the northern part of the Carpathian loop; the region extends south-eastward into Roumania, but becomes less and less productive in this direction. The oil-bearing zone extends over a length of some 500 km.

The Carpathian ranges form a strongly folded and overthrust mountain system, including very complicated structural forms. The petroliferous zone, however, occurs exclusively along the frontal belt, but extends a considerably greater distance into the more strongly deformed zone than is the case in the Appalachian Mountains of North America, where production is confined to the only very gently warped foreland.

Like all major systems, the Carpathian chain is bordered by an outer depression in the foreland, a structural 'foredeep', in front of the actual ridge. This sub-Carpathian region is only gently undulating country; it narrows to the south-east, where it is confined by the Podolian Plateau: to the north-west it expands more widely. Partly saline Miocene formations prevail on this foreland, largely obscured by Quaternary surface deposits. Carpathian folds, consisting of Oligocene strata, however, are concealed at depth. There is unconformity between the Upper and the Lower Miocene. The actual mountain front is made up of a series of overthrust masses, which are again divided in several slices ('skiby'). The mountains consist of Cretaceous, Eocene, and Oligocene rocks, which have been thrust over the Miocene foredeep. Three major overthrust masses can be distinguished: the 'Marginal' belt of the outer front; the 'Median' belt, marked by a distinct longitudinal depression lying behind the slightly more elevated Marginal zone; and finally a more central elevated ridge in the south-west, the 'Magura zone', which passes into Czechoslovakian territory.

The oil production in the Marginal belt is derived from Oligocene and Cretaceous strata, in the oilfields of Schodnica, Boryslaw, Tustanowice, and Mraznica. In the Median belt production is found in Eocene and Cretaceous beds in the oilfields of Kleczany in the west, the Jaslo-Protok-Krozno group of oilfields in the centre, and some eastern outlying fields at Wankowa and Pajskie-Polana. In the central Magura zone only unimportant occurrences are known: Ropica and Ropianka. About 100 known oil- and

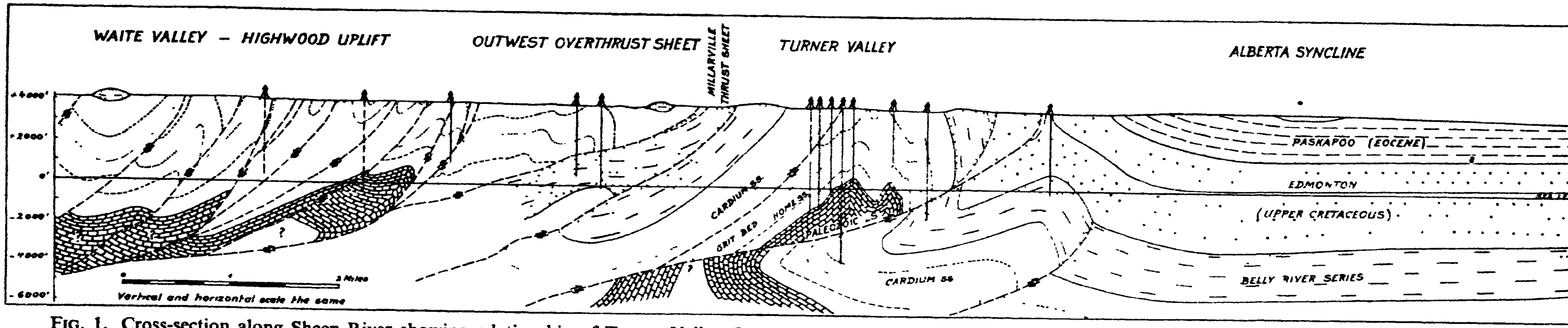

FIG. 1. Cross-section along Sheep River showing relationship of Turner Valley, Inner Foothills, and Alberta Syncline. After Th. Link and P. D. Moore (*Bull. Amer. Assoc. Petr. Geol.* **18** (1934)).

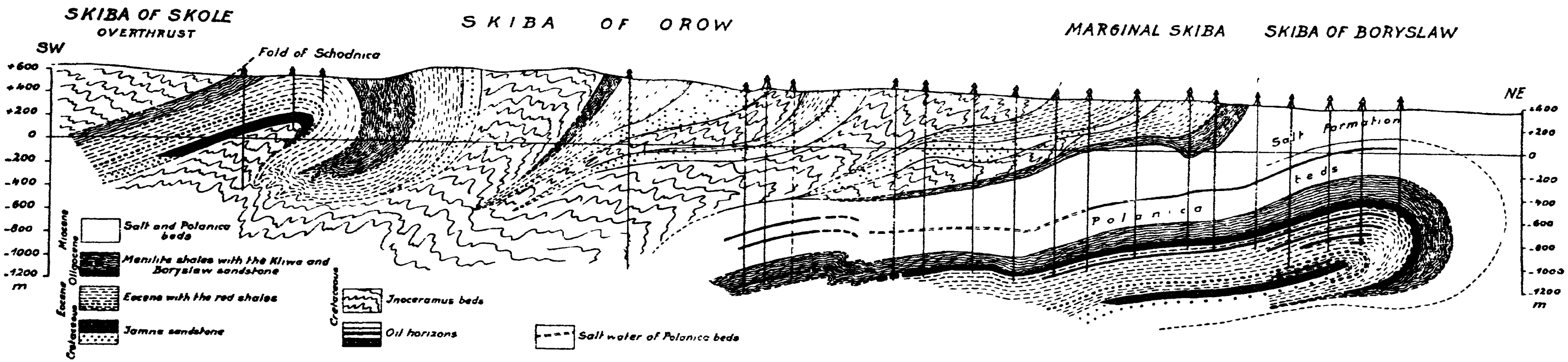

FIG. 2. Geological section, showing structure of Northern Carpathian Range in Boryslaw region. Length of section from Dinar 382 at south-west to Magda at north-east, and is approximately 9,900 metres or 6 miles (Carpathian Geological Survey). After K. Tolwinski (*Bull. Amer. Assoc. Petr. Geol.* **18** (1934)).

gas-producing areas are scattered over the total area. Only a 'dry' gasfield has so far been found on the actual foreland: Daszawa gasfield, east of Stryj. Exploration of this region, however, with its folded and obscured substratum, is still incomplete.

The long slices, or 'skiby', of the front may be compared to those known from the Appalachian Mountains; they are long, generally parallel thrustblocks which may extend for hundreds of kilometres. In the Boryslaw district the outer slice, largely obscured by the foreland Miocene, is 'the Boryslaw skiba'; it is over-ridden from the south by 'the Marginal skiba'; this in turn by the 'skiba of Orow', and over this, farther south, the 'skiba of Skola' is thrust (this latter slice already belongs to the Median belt). These skiby consist of folded Cretaceous, Eocene, and Oligocene rocks. Petroleum deposits occur in the Cretaceous Jamna Sandstone, a fine-grained porous sandstone of varying thickness, up to 30 metres. The main production is found in the Boryslaw Sandstone, a fairly porous sandstone, averaging 20 metres, with variable porosity and hence erratic production, near the base of the Oligocene Menilite shales. The Eocene shales are somewhat creviced and may contain oil or gas on joints and bedding planes, but good reservoir sands do not occur. The element of the outer Boryslaw skiba extends for a long distance to the north-west and south-east, along the entire mountain front, and yields production 100 kilometres to the south-east of Boryslaw, at Bitkow. The number of individual folds varies in this skiba. The Miocene foreland contains beds of rock-salt, which cause diapir folds in the southern, more intensely folded belt (cf. sub. 3). Farther away from the front the folds become broader and flatter (Daszawa gasfield).

Fig. 2, after K. Tolwinski [3, 1934], gives a south-west to north-east section through the overthrust and drag-folded complex which contains the Boryslaw-Schodnica oilfields, in the Marginal zone. In the Jaslo district in the western Carpathians, 140 km. north-west of Boryslaw, oil is produced from long narrow and steep anticlines in calcareous clays and sandstones of Oligocene age, with an Eocene and Cretaceous core (Potok anticline). The reservoir rocks are here in the lower-Eocene and upper-Cretaceous sandstones.

The little oil produced in the Magura zone of the Jaslo district is of a density 0·720–0·870 (= 65–31° Bé.); these fields are on the margin of the Magura mass, where it is thrust on the Median complex, and are evidently derived from the latter.

In the Median zone of the Jaslo district the oils vary still more widely in density: from 0·700 to 0·950 (= 70·5° to 17·5° Bé.), but are mostly around 0·850 (= 35° Bé.) in the more important productive areas.

In the Marginal belt, in the Boryslaw area, the oils average 0·850 in density (= 35° Bé.); at Bitkow in the south-east; *c.* 0·810 (= 43·2° Bé.).

All the oils are generally of paraffin base.

The comparatively heavy nature of many of these oils is still more surprising for a zone of more intense deformation than at Turner Valley, in Alberta. It proves that metamorphism is by no means necessarily a consequence of strong dynamic thrust. It is true that the primary origin of the Carpathian oil is still in controversy, and that the accumulations in the strongly folded and thrust strata may have migrated into them from below, after the diastrophism. However, the substratum of the Carpathian thrust-sheets must also have been subject to tremendous stress and drag, under a terrific load. According to Petrascheck, coals occurrin below the Carpathian thrustsheets are totally unaffected by metamorphism, a condition greatly differing from the Appalachian coalfields, and explaining why oil has been preserved in the substratum.

Oil has been produced for a long time in the northern Carpathians: at first from natural seepages and hand-dug pits; modern development dates from about 1860. Prior to 1916 most of the considerable amount of gas associated with the oil was allowed to escape; at present there are gas-lines (150 km. to the city of Lwow and 77 km. from Jaslo to Tarnow), and some 25 natural gasoline extraction plants. Boryslaw has produced from 1886 to 1932, 23,500,000 tons (174 million barrels) of oil and more than 5,000 million measured cu. metres of gas (176,500 million ft.), from 1916 to 1935. The total quantity of gas wasted prior to 1916 is estimated at 10,000 million cu. metres (353,000 million ft.).

The gas-oil ratio is about 60 cu. metres of gas per 100 kilograms of oil (= about 3,000 cu. ft. per barrel). Natural gasoline produced amounted to 38·8 million kilograms, from 251 million cu. metres of gas treated, equal to about 1·5 gallon per 1,000 cu. ft. of gas.

For further information the reader may be referred to articles by Ch. Bohdanowicz [4, 1933], and K. Tolwinski [3, 1934].

3. **Saline structures** are frequently associated with oil deposits. Since they result in intense dislocation of strata, these structures may be mentioned when discussing oilfields in folded rocks. They occur when a stratigraphical sequence contains intercalations of rock salt, anhydrite, or gypsum, or even mere shaly strata with a considerable admixture of salt grains. Rocks of this nature behave as a plastic material whenever they are subject to pressure, either through orogenic thrust or through the weight of mere overburden.

Saline formations occur in all geological periods, from the Lower Cambrian (Hormuz Series of the Persian Gulf region) to Recent. The most important bodies of water in which salt is now being deposited are inland lakes, such as the Great Salt Lake of Utah and the Dead Sea. Contemporary marine saline lagoons are in all cases marginal to larger bodies of normal sea like the Red Sea, the Caspian, or the Gulf of Mexico. A classical example is the Qara Bughaz in Transcaspia. It would seem that the climatic conditions of the present time are nowhere sufficiently severe to cause such widespread marine concentration as has evidently occurred at some times in the past, notably in the Permo-Triassic and Middle Tertiary periods.

When a salt formation is buried under as little as 2,000 ft. of sediments, the pressure (about 170 kg/cm.^{2}) already begins to render the salt plastic, as is shown by its behaviour in salt-mines (Mines Domaniales of Alsatia). When the formation is more deeply buried, the extra pressure forces the plastic salt and gypsum through the cover of overlying rocks: it bursts through as circular intrusive plugs (salt-domes), entirely comparable to volcanic necks. The mechanics are evidently very similar. This is another case of 'sedimentary volcanism'. Tangential pressure does not seem to be required for the formation of these circular vents: the mere weight of the overburden (between 20–30,000 ft. for the Iranian salt-domes, at least 15–20,000 ft. for the American Gulf Coast) appears sufficient. Fulda has assumed that a thickness of overlying sediments of about 11,000 ft. is necessary before a neck of salt can burst through overlying competent strata by the sheer weight of rock pressure. Once a vent is formed, isostasy may keep the salt moving upward until equilibrium is

attained. Thus a salt-dome can rise above the surrounding topography.

When, in addition, tangential pressure, caused by orogenetic thrust, acts on a sequence containing a saline formation, the salt beds behave like a lubricant and are responsible for a sliding and independent crumpling of the overlying rocks leading to an extreme structural discordance between them and the underlying rocks. Sliding and independent folding of this nature explains the structure of the Jura Mountains of Switzerland and France, where the thrust of the Alps appears to have sheared the entire blanket of Upper Mesozoic strata off its pre-Triassic crystalline base; it was compressed into folds, whilst sliding over the Triassic saline formation that underlies the mountains. The structure of the front of the Iranian Mountains of Iran has been found to be something similar. Since the rigid Asmari Limestone, 1,000 ft. thick, underlying the saline Lower Fars formation (Lower Miocene) is the prolific oil reservoir of this petroleum province, the task of the geologists is the detection of suitable covered structures in this presaline formation. There it was soon discovered that the surface folds offer no guidance: that superficial anticlines have been thrust over synclines, and that the violent contortions and faulting have no counterpart in the broad simple folds of the limestone basement. The plastic salt and anhydrite have moved from some parts of the structure and have been massed to considerable thicknesses in others (the so-called Omega-fold of Busk). The rather involved structure following the northern and western edges of the Harz Mountains, and elsewhere in the north German plains, very probably had a similar cause.

When upthrusts of salt and tangential pressure act together, very complicated diapiric salt anticlines result in which the saline beds are thrust through the crest of the anticlines. Beautiful examples of such structures are described from the southern front of the Carpathian arc in Roumania. Circular salt plugs, however, also occur in previously folded regions (for instance, in Iran and in Moldavia) and clearly show the independence of such vents from normal folds, and also that the age of the uprise of the salt is not necessarily related to periods of folding of the strata they have pierced. In Iran the salt-domes are in general associated with anticlines, but they are not regularly located on the highest part of such structures, but rather on the pitching ends or on the flanks, quite indifferently. Some few are situated in synclines. Also, rarely are there visible lines of dislocation or major faulting which could account for the distribution of the plugs. This independence indicates that it is not so much tangential pressure that causes the salt necks to rise, but rock pressure by weight; sometimes these agents act simultaneously, in other cases they may be entirely unrelated and take place at different times.

The columns of salt contain an enormous amount of material. A salt plug which emanates from a stratum 20,000 ft. deep, and has an average diameter of a mile and a half (which is the order of size of very many salt-domes), would have its salt requirements satisfied by the material contained in a bed of salt 150 ft. thick over a square with a 15-mile side. Since in many regions salt-domes are very numerous and close, it is very probable that the entire original supply of salt has been exhausted and that many deep-seated domes, such as are known on the American Gulf Coast, have not been able to reach the higher levels on account of a lack of supply. If it were possible to reach the parent salt horizon by drilling, no salt would be encountered. Some plugs appear to have been pinched by lateral pressure and assumed an overhanging mushroom shape. They may even have become disconnected from their base and been squeezed upwards independently, and may now be rootless.

Saline domes occur wherever saline formations are buried at sufficient depth. We know them from America (Texas-Louisiana, Utah, Mexico, Bolivia), from Germany, Spain, Roumania; from North Africa, Egypt, Palestine, Arabia, Transcaspia, Iran, India; and continuously new finds are being reported. The Cambrian salt-domes of southern Iran are probably the most spectacular in the world. More than 100 of them are mentioned by G. M. Lees. Their average size is about 3 miles in diameter, and in some cases they form mountains as much as 4,000 ft. above the surrounding country. They present some unique evidence on the plasticity problem. In the case of several of the higher domes the salt has even commenced to *flow* downhill as a 'salt-glacier', whilst the rock-salt remains solid, with its normal banded structure, and is totally distinct from a slide of debris. Evidently, the salt continues to rise within the plug and thus supplies this overflow. Since rock-salt is known to acquire an exceptional plasticity when wetted, the occasional rains of the region (yearly rainfall about 3 in.) play a part. Even 'gypsum-glaciers' are reported by A. Wade from the northern Red Sea area.

Not all salt-anticlines and salt-domes are associated with oil deposits. They can only carry oil if an adequate supply from source beds is present in the area. Since the saline facies is generally favourable to the genesis of petroleum (see article on the Stratigraphical Distribution of Petroleum) we find many commercial oilfields connected with saline structures, the latter having favoured migration and accumulation in reservoir rocks. The upthrust of the salt core, either in diapiric folds or in salt-domes, has often dragged the adjacent beds, sealing their upper ends against the salt, and thus created good reservoirs in strata of favourable porosity. Sometimes the salt plug is covered by a cap-rock, often a dolomitic, more or less cavernous mass of cemented residue remaining after partial solution of the salt. If oil can find access to a rock of such nature, it finds an excellent reservoir, and a prolific oilfield may result (Spindletop, &c.). As in all oilfields, a series of favourable circumstances and events must coincide, i.e. genesis, migration, accumulation, and, last but not least, preservation of petroleum.

For further information, the reader may be referred to the Symposium on Salt-domes [5].

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THE ROLE OF FAULTING IN THE ACCUMULATION OF OIL AND GAS

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A FAULT is a fracture in the earth's crust resulting in a relative displacement of the rocks on either side of the fault-plane. Unless the fracture takes place along the bedding-planes it involves a break in the continuity of the sedimentary layers, and if the stratigraphical displacement is sufficient the broken edges of a stratum are completely separated at the fault-face. Should this involve the juxtaposition of two formations which are essentially dissimilar in their physical nature, the resultant effect is to introduce an anomalous condition in the neighbourhood of the fault which will greatly affect the flow of liquids through the rock masses in its neighbourhood.

There are three physical and geological effects associated with faulting which require consideration. Firstly, the physical continuity of the beds is disturbed so that fluid movement along them is affected in the neighbourhood of the fault. Secondly, the physical nature of all the competent rocks broken by the fault is liable to be altered by secondary fissuring which will increase their permeability. In the third place the formations close to the fault-plane are liable to suffer secondary warping or fracture which alters their attitude and results in anomalous structures near the fault.

The incidence of these three alterations in the physical condition of the strata may produce the following effects so far as oil movement and accumulation are concerned.

(*a*) *Trap Structures.*

Where the fault displacement completely breaks the continuity of a porous horizon and the torn edges of the latter become plastered with a mass of plastic and impervious material, the continuity of flow through the porous rock is broken. Should the fault lie athwart the line of oil and water migration, the area adjoining the fault becomes a zone of stagnation and an oil trap may be produced. Where the displacement merely throws one porous horizon against another the changes in permeability are not important and no trap will result.

(*b*) *Associated Trap Structures.*

A fault represents a reaction to a local condition of strain. The resulting fracture is not usually the only reaction, for the strata may be warped as well as broken. This distortion near the fault usually involves some longitudinal and considerable cross-folding. Such readjustments to the local stresses may produce trap structures in themselves apart altogether from the main fault.

(*c*) *Induced Permeability.*

Where the fault-plane intersects rigid formations there is often considerable fissuring of such strata. This provides additional porosity and at the same time greatly increases the permeability of the formation as a whole. Such features may greatly increase the productive capacity of the formation.

(*d*) *Vertical Migration.*

The induced fissuring associated with fault-planes may lead to extensive oil and gas movement wherever such fissures remain open. In many cases this has led to the escape of oil and gas at the surface. In other cases the movement produces secondary accumulations at higher horizons which are in communication with fault-planes.

(*e*) *Contact Enrichment.*

The fault displacement may bring a rock into contact with a source rock. In this case oil-flow may occur across the fault-plane and a commercial accumulation may be produced in the porous rock.

Fault Traps (*a* and *b*).

A normal strike fault produces the simplest type of trap structure in so far as migration of oil and gas are usually up dip, and such a fault will lie athwart the movement. Where a porous reservoir is covered by an impervious and plastic cap and the latter is downthrown on the up-dip side, the plastic rock seals the reservoir on its upper truncated edges and a perfect trap may be produced. The sealing effect of such fault structures is greatly enhanced by the longitudinal closure with which they are usually associated. The zone of maximum faulting in the middle of the up-faulted block has often developed sufficient up-warping in itself to form an anticlinal trap, and the resultant structure is both a faulted and folded one. Luling is an excellent example of a structure in which faulting alone is the cause of the accumulation. The structure of the down-dip side of the fault is unaffected by folding, and the oil in the Edwards Limestone has been trapped by the down-faulted clays of the Taylor Marl [2, 1929] (Figs. 1 and 2). On the other hand, the Mexia structure is also associated with considerable warping of the crest of the structure close to the fault-plane, and an appreciable amount of closure must have been induced by these folded conditions [3, 1929]. Both of these examples are probably cases of the trapping of oil during lateral migration, and there is little evidence to support the view that they represent oil accumulation produced by vertical migration up the fault-planes [4, 1934].

It is a significant feature that practically all the fault fields of the Balcones Fault Region represent up-faulted blocks with the downthrow on the western side. They may be complementary to the main Balcones Fault itself which has a movement in the opposite direction, and represents a general subsidence towards the Mexican Gulf. The fact that it is the subsidiary faults and not the main one which contain the oil accumulations may be partially due to the fact that they lie between the main fault and the source of migration, and would therefore have intercepted the oil. This, however, does not appear to be the only reason, and it is more probable that such fault structures are usually associated with longitudinal as well as transverse closure,

whereas this is not normally the case with a fault where the dip and downthrow are in the same direction.

Dip faults on a simple monocline do not show any tendency to trap oil, but where such dip faults occur on the crests of anticlines, the closure due to a combination of folding and fracture often produces important segregations of oil on these fault segments. A plunging anticline cut off by cross-faulting from the main crest may produce a local closed structure which is as efficient as the main dome in spite of the fact that it is not the highest point on the main structure.

Strike faults on folded structures may produce local traps just as they do on monoclines, the folding already present helping to increase the efficiency of such structures.

Sometimes an association of two or more oblique faults on a monocline produces a sector bounded up dip by an obtuse angled set of intersecting fault-planes. Such structures produce effective reservoirs, provided the faults are themselves sealed, for longitudinal closure is taken care of very effectively by the obliquity of the fault-planes.

Some strongly folded anticlines have their steep limb shattered by reversed faults. The resultant effect from an oil accumulation point of view is to break the continuity of the producing horizons and sometimes to repeat the latter in a vertical section, thus creating an upper and lower producing horizon separated by the reversed thrust. In most cases the thrust consists of the more plastic portions of the sequence squeezed and shattered by the intense movement, and it forms an excellent seal to the oil in the underthrust segment.

Occasionally oil is found in commercial quantities under regional thrusts of still greater dimensions, a classical example being the Boryslaw field of Poland. In this case, however, the sealing effect is due more probably to the plastic nature of the Miocene clays than to the effect of the overlying thrust.

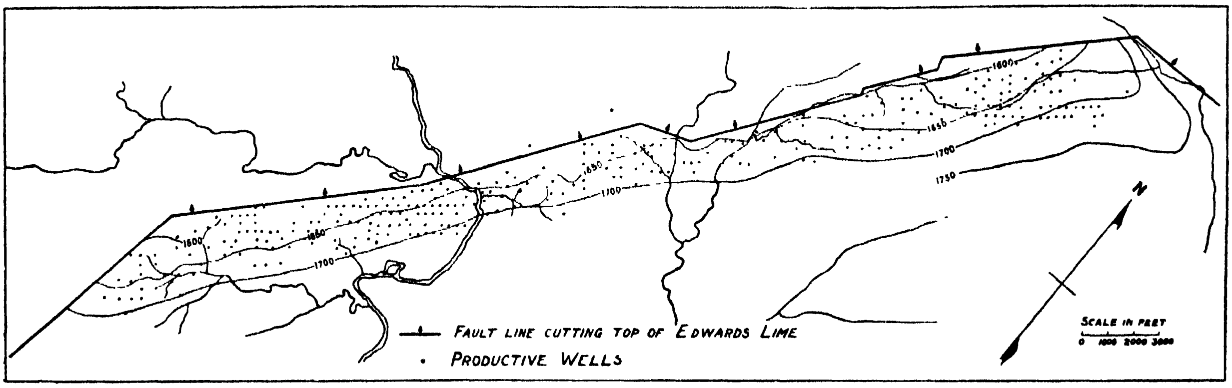

FIG. 1. Structure map of the Luling field (after Brucks). The contours are drawn on the top of the Edwards oil horizon. Datum plane: sea-level.

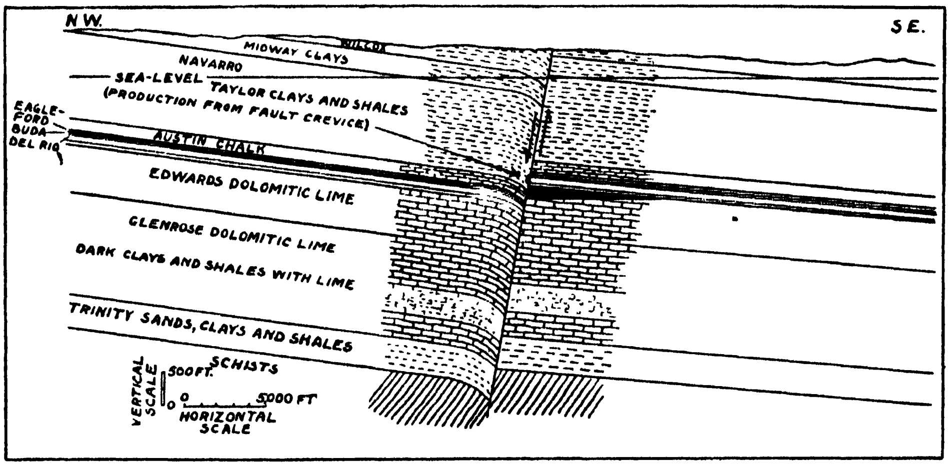

FIG. 2. Generalized north-west–south-east cross-section showing structure and stratigraphy of the Luling fault (after Brucks).

Induced Permeability (c).

In some oil-pools, particularly those containing limestone reservoirs, the fissuring produced by faulting and accentuated curvature due to torsion plays an important part in rendering the oil rock more permeable. Such open fissured conditions are commonplace in mineral lodes, but there has been a reluctance on the part of oil geologists to accept the idea that open fissures occur in these rocks. There is, however, no valid reason why such fissures should not occur, provided the rocks are sufficiently competent to maintain them. The large gash-veins filled with solid bitumen are good examples of such open fissures, and the open cracks, joint-planes, and fault fissures which have been found filled with gas-carried muds as features of sedimentary vulcanism are other examples. Wells which penetrate into such fissured conditions are liable to give abnormally high production, which is probably due more particularly to the increase in permeability than the change in the porosity.

Vertical Migration (*d*).

There can be little doubt that while faults may in some cases seal the oil in the reservoir rock, they are often more important as the avenues of extensive oil and gas movement across the strata [5, 1923; 6, 1919]. The association of faults with lines of seepages is one of the most obvious examples of this action, and lines of mud volcanoes lie more commonly on faults than on any other type of structure. Where an oil source is deep-seated this vertical migration along fault-planes plays an important part in the carriage of the oil to shallower portions of the structure, and there are numerous examples of such vertical oil movement, particularly in regions of disturbed tectonics. Such conditions lead to the accumulation of oil at successive horizons in a single structure, or a major reservoir may lose some of its constituents to minor reservoir rocks at higher levels. Occasionally the rocks caught up in the fault-plane may become highly impregnated, and a small but often very rich zone of oil may be found in the fault block. There can be little doubt that gas and oil may move in this way across thousands of feet of strata, and if such movement be given free play it forms a powerful aid in the concentration of oil in the rocks which come into contact with the fault. Admittedly, such fractures may, on the other hand, lead to the bleeding of good reservoirs and to the loss of oil and gas at the surface.

One of the most striking examples of fault accumulation with probably considerable vertical migration is the marginal accumulation on the edge of a salt-dome. The salt boundary is essentially a fault-face in so far as it represents the slip-face along which the salt has burst through the strata. In addition there are numerous subsidiary faults close to the salt edge, and the rich accumulations which occur locally on such margins probably result from intense oil concentration in zones of considerable vertical migration. The faults in these cases have probably focused the oil movement and then trapped it on the edge of the salt.

Contact Enrichment (*e*).

Lastly, we have the action of faults or thrusts in bringing source rocks and reservoir rocks into intimate contact and thus leading to an oil accumulation. It is not always realized that many a potential field has failed to materialize, not for the lack of oil, but because suitable reservoir rocks were not available, for it seems probable that the conditions which produce oil do not normally produce reservoir rocks. Sometimes this association of the two rock-types has been produced by faulting and thrusting. A good example is provided by the Bustenari field of Roumania, where the Oligocene has been thrust over the Miocene and has apparently been enriched with oil from that source [1, 1912].

This brief résumé of the role of faults in oil accumulation has been restricted of set purpose to the part played by faults in forming the accumulations. There is another aspect of the subject in the part played by faulting in permitting changes in the oil and water zones, as secondary water circulation commences in the reservoir. However, it may be said that faults have, in fact, three primary functions. They produce local trap structures when the conditions are favourable. They increase the permeability of the reservoir rocks and add to their capacity to allow free oil flow. Lastly, by inducing vertical migration they bring deep-seated oils close to the surface, and though in some cases this oil is lost, in others it is segregated in shallower reservoirs where it can be produced economically.

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SALT STRUCTURES: THEIR FORM, ORIGIN, AND RELATIONSHIP TO OIL ACCUMULATION

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STRUCTURES with salt cores of a wide range of forms occur in various parts of the world. Many have long been known, some having been worked for their salt content, whilst others are of importance on account of the oil which has accumulated about or over them. The presence of salt in some of the latter was realized before oil was discovered, but for others its presence has only been proved after a considerable number of oil-wells have been drilled. The association of oil with salt-cored structures has led to an intensive search for these at increasingly greater depths, yet much of our knowledge of their structure and origin has been obtained from salt masses which have been exploited for their salt content and near which little or no oil has been found.

In the U.S.A. the first oil-well completed on a salt structure was at Spindletop in 1901, whereas in Roumania oil has been produced from the beds around salt masses since the latter half of the nineteenth century. In Germany oil in relatively small amounts has been found around salt masses and in their exploration, and within the last few years, test bores drilled from the galleries of a salt-mine at Volkenroda encountered oil in commercial quantities in the Middle Zechstein Hauptdolomit. Oil has also been found in association with salt masses in other parts of the world. Some very prolific wells have been drilled on salt structures, and the oil production from such sources is of no mean order, for over a thousand million barrels have been obtained in the Gulf Coast region alone, and more than half that amount in Roumania.

The Structures of Salt Masses and the Surrounding Beds

A complete range of salt structures is known from a normal salt bed through salt anticlines to stock-like masses of salt, yet even in the simplest forms, where the salt closely follows the gentle folds of the enclosing beds without marked thinning or thickening, it is apt to show structures which are not present in the other beds. In salt anticlines a thickened mass of salt has arched the overlying beds into an anticlinal form and is probably itself, in many instances, on the crest of a less strong fold. The salt may penetrate the overlying beds a little. Its internal structure, while generally anticlinal, usually shows complications. The extreme form of the salt is the stock—circular, elliptical, elongated, or irregular in plan and penetrating the beds which would normally overlie it, for great distances vertically. Strong contortions and flow structures are seen in the salt. Generally the sides of the stock are steep, and it may even taper downwards. The surrounding beds usually dip away steeply, to become much less steep at a short distance from the salt, and often their dip increases with depth in any vertical section near the salt. Where the salt does not reach the surface the overlying beds are commonly domed, although there are instances where a graben overlies the salt, preserving young beds within a ring of older ones. Unconformities may occur in the beds above or near the salt, and radial and peripheral faults are probably very frequent. These faults are not always easy to detect on account of unconformities, drawing out of beds, and other structural complexities.

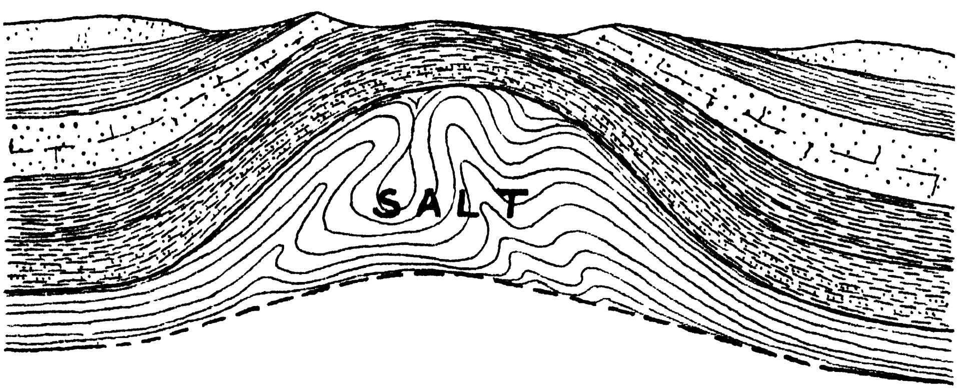

FIG. 1. Hypothetical cross-section of a salt anticline. The base of the salt is shown arched, but whether such a feature is necessarily correct is not proved.

A full range of salt structural forms occurs in the North German Zechstein Basin. The least deformed salt beds are marginal and where downward movement of the beds ceased in the early Jurassic; the salt stocks are found where the sinking and sedimentation in post-Variscan times was strong, whilst salt anticlines occupy the intermediate areas. According to Stille [17, 1926], there are cases where, in tracing a single line of uplift into the basin, the form of the anticlines goes over more and more to the form of a salt stock.

Salt masses in Roumania are widely scattered, their maximum occurrence being along the edge of the nappes. They tend to lie on curving lines parallel to the edge of the Carpathians. Usually they are elongated in plan and lie along the anticlinal crests and fault lines, but a few appear in synclinal areas or cut across anticlines. At times the salt masses seem to be overthrust and possess projections. Many have old beds at the surface on the upthrust side and

young beds on the other, but some have young beds on both sides. The salt is almost pure sodium chloride. However, there may be much mechanically infolded clay, sand, and carbonaceous matter, especially in the upper parts, and the breccias which are frequently found on the margins of are reported near Dudinsk and in the Cape Nordwick area. Little information is available concerning the salt structures of the U.S.S.R., except that it appears that they are more faulted than those of the Gulf Coast of America.

The majority of the salt masses of Iran have burst through

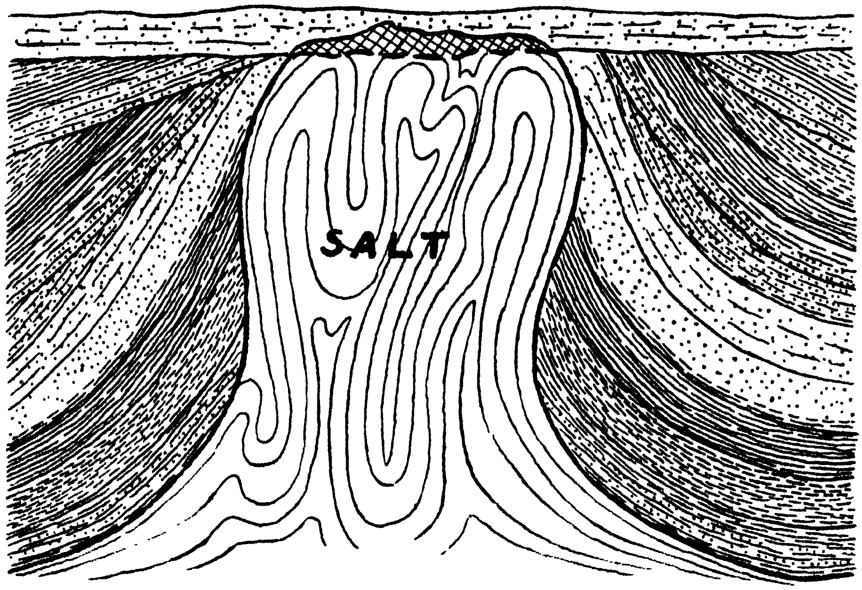

FIG. 2. Hypothetical cross-section of a salt stock, on the top of which is a salt table (cap-rock). Salt stocks range from a fraction of a mile up to several miles in breadth, and may be several miles long.

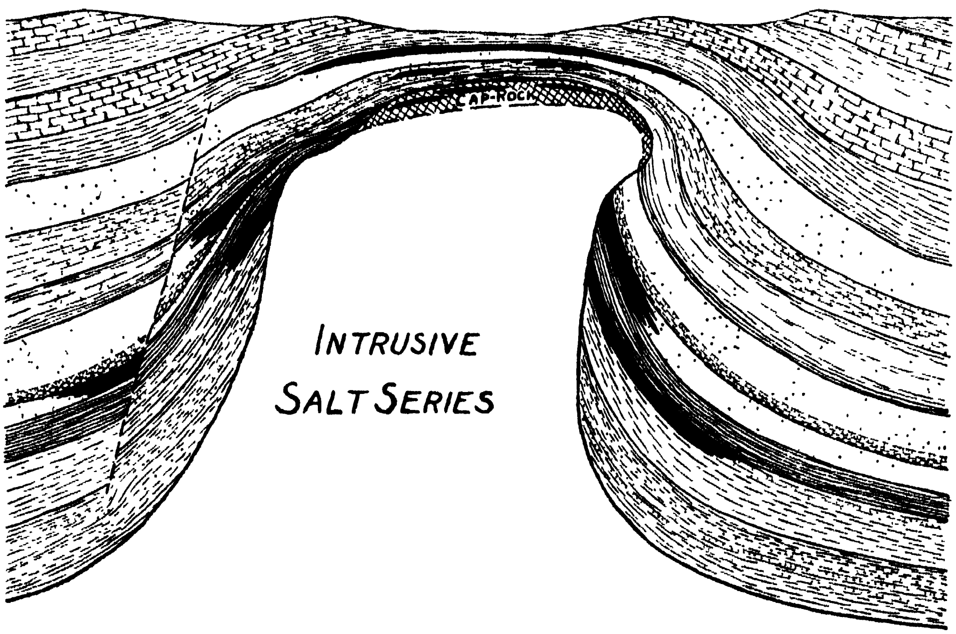

FIG. 3. Simple cross-section showing possible sites of oil and gas accumulation over and about an intrusive salt mass: super-cap, cap-rock, and various types of flank accumulation. The oil and gas are shown in full black.

the salt have been the cause of much controversy in connexion with the age of the salt [19, 1926].

Salt cores are common in the marginal folds and fractures of the Transylvanian Basin, and it is thought that they may be present at depth in the centre.

Many salt structures have been discovered by geophysical methods in the Ural-Emba region of the U.S.S.R. Others

the folded beds bordering or covered by the Iranian Gulf [8, 1931]. Some occur on the north-eastern edge of this folded zone where faults are numerous, and others pierce the Mio-Pliocene deposits of the Median mass which forms much of the high plateau of central Iran. Those connected with faults are dyke-like, although it is uncertain how far the faults are the cause or effect of the salt uprise

[12, 1931]. The others are circular or elliptical in plan. Most of the salt masses or plugs are associated with anticlines. Often they are not on the crest, but occur on the flanks or the pitching ends. The injected material is a mixture of salt, gypsum, and red shales.

Intrusive salt bodies are known in coastal Asir, Arabia, being seen in the regions of Salif, Loheiya, Guma, Gizan, and in some of the Farsan Islands [20, 1931]. A salt mass occurs at Jebel Usdum, Palestine, and others have been recorded from North Africa [3, 1932] and Spain.

A very important series of salt masses, typically of the stock type, is found around the Mexican Gulf, in the U.S.A., and Mexico. The Gulf Coast salt-domes fall into three main groups separated by barren areas—the Coastal, the Texas Interior, and the Louisiana Interior groups. The salt is covered by arched beds when it does not reach the surface. According to Hanna [7, 1934] only one salt-anticline has been delimited in the Gulf Coast province—Boggy Creek, Texas. The presence of rim synclines and overhang has been shown on some of the domes. A variable proportion of disseminated anhydrite is found in the salt, some salt cores showing as little as 1%, whilst the average is 5–10%. Elongated salt masses occur on the Isthmus of Tehuantepec.

The salt cores of the Utah-Colorado structures are generally very impure and they are connected, at least in part, with a series of parallel anticlines. In some cases the cores are plug-like [9, 1927].

In Germany, Mexico, the Gulf Coast, and possibly also in the Utah-Colorado region, it is common to find on top of the salt masses a 'cap-rock' consisting of anhydrite and gypsum. At times these are accompanied by 'limestone', dolomite, and sulphur, the sulphur and 'limestone' being a feature of the Gulf Coast salt-domes. The thickness of the cap-rock may vary from a few feet up to several hundred feet; it may cover part, or all, of the top of the salt, and on some domes it extends some distance down the side of the salt. Often it shows signs of brecciation and is highly porous. Cap-rocks are not known in Roumania.

Surface Indications of Salt Structures

When the salt approaches or reaches the surface it gives rise to a variety of features. Salt springs, depressions, marshes, and ponds are seen over some salt masses in Roumania, Germany, and the Gulf Coast. A number of the German salt structures are marked by a dropped-in mass of young beds, and some of the Interior domes of the Gulf Coast and Mexico are well expressed in the surface geology. On the other hand, surface mounds, slight or strong, may occur. In some instances in Germany there is a mound of gypsum, and the Gulf Coast domes are frequently revealed by a slight mound of sediments. By far the most striking indications of this type are shown by the Iranian salt plugs, some of which rise several thousand feet above the surrounding country, lifting an aureole of beds with them. The salt may stand above the encircling sediments, its preservation being due to the low rainfall, and may send out glacier-like tongues of salt [8,1931; 12, 1931]; or it may lie below the rim of uplifted beds, as a central depression, covered with an alluvial cloak of weathered-out clay and breccia.

Theories of the Origin of Salt Structures

The mode of origin of these salt structures is still a subject of controversy. Uptilted beds around the salt and other characteristics point to the intrusion of the salt from below. Hence, it is not surprising to find among the earlier hypotheses suggestions of a volcanic origin from analogy with some of the features shown by igneous intrusions [4, 1926]. At a later date Goesmann advanced the theory that the salt had been deposited from solution. This was elaborated by others, including Fenneman and Harris, who pictured the forces exerted by growing crystals as giving rise to the domed strata and surface mounds. According to Harris, writing of the Gulf Coast, artesian waters descended through porous beds, became heated, and took into solution salts encountered in Palaeozoic and Mesozoic beds. Under hydrostatic pressure the solutions rose at points of weakness in the beds, these points occurring mainly at the intersection of faults in the pre-Tertiary beds. Near the surface where the temperature and pressure were lower, deposition of salt set in. A core of salt formed which was pushed upwards by further crystallization of salt at its base. Thus the beds would be arched and penetrated, and near the surface the salt mass might be beheaded by subsurface waters.

Such theories are chiefly of historical interest, for critical examination shows them to have serious defects, and it is to theories based on the deformation of a normal sedimentary salt series that attention must be paid. Much of the data which has led to the formulation of the 'plastic flow' theories has accrued from observations on the German salt masses, for in that country all phases, from the undisturbed salt bed to a salt stock, are known.

Estimation of the thickness of a continuous salt bed which could supply the volume of salt present in the salt masses known in the Gulf Coast and Iranian regions, gives figures of the same order as those recorded for various salt series which are believed to have been formed in lagoons, embayments, or shut-off bodies of sea-water [6, 1920]. These salt series are complex: ideally they consist, from the bottom upwards, of zones characterized by calcium sulphate, sodium chloride, and then the more soluble magnesium and potassium salts. In particular instances only part of the full series may be present, or there may be repetitions and mixing of varying degrees of importance, depending on the detailed history of the area in which salt deposition took place. As a result of wide variations in composition, constitution, conditions of burial, and geological environment, it is difficult to generalize as to the behaviour of salt series. However, it is widely accepted that salt behaves plastically. Therefore, a critical pressure gradient must be attained before the salt will flow. This critical pressure gradient is probably affected by the thickness of the salt mass, and according to Stille [17, 1926] the carnallite zone is less plastic than the rock-salt, whilst the anhydrite is the least plastic component. (Murray Stuart [18, 1931] has put forward certain evidence in India as indicating an increase in plasticity in ascending the ideal salt series.) Consequently, in Germany the 'main anhydrite'—an anhydrite bed 40–50 m. thick and some distance up in the salt series—behaves differently from the rock-salt and potash salt. Usually it does not partake of intense folding, but shatters, and in places the more mobile salt wells up through gaps in the 'main anhydrite'. It may also be that the plasticity of the salt is dependent on the absolute pressure. If increase in absolute pressure increases the plasticity, then under the higher pressures a lower pressure gradient will be necessary to cause flow. Therefore, as the salt approaches the surface it will become less plastic and will behave more like a true solid. It is probable that the rise in temperature with depth of burial will increase the

plasticity and that the water content will be important in determining the ease of flow.

There are two main schools of thought concerning the source of the forces which cause the salt to flow and so give rise to these remarkable structures. According to one, any irregularity in the load on the salt bed which gives rise to a pressure gradient in excess of the critical value will lead to flow and uplift of the salt. The size of the requisite irregularity will depend on the relationship between the depth of burial and the plasticity of the salt, as well as on the constitution of the salt bed. Such an irregularity may arise from the accidents of deposition of the salt or of the beds above it; from weak spots in the enclosing beds; from extensive erosion of parts of the cover; or from arching of the salt and enclosing beds and erosion of the anticlinal areas. Once the salt begins to rise, then the fact of its density generally being less than that of the surrounding beds will enhance the pressure differential, in so far as the increment due to density difference exceeds the additional resistances introduced by friction, especially on the margins when the salt is penetrating the overlying sediments, and the load added in raising beds. It is likely that these two retarding influences will be relatively less important as the diameter of the rising salt mass increases. A sinking area with a growing load of sediments might, according to this theory, have salt plugs and anticlines, and these could occur, at the surface at any rate, in otherwise unfolded beds. Uplift or penetration of the overlying sediments would be dependent on their properties and on the amount of salt movement, and in the absence of faults the intrusive masses might be expected to be more circular the farther they had risen.

Kraus [11, 1923] has shown that the accepted form of some salt masses approximates to that to be expected from the lateral thrust due to a settling area.

The other school of thought maintains that the rise of the salt is due to lateral pressure in the earth's crust. Stille [17, 1926] considered the salt upthrusts as an extreme case of disharmonious folding in which the cores of anticlines had burst through the overlying beds. He conceived the upthrust less as the injection of an especially light material than as the injection of an especially mobile material. The rounded plan of many salt stocks has been taken as evidence of the absence of tangential pressure, but he pointed to the occurrence of domes in non-saline formations at the intersection of axes of uplift. In at least one salt mass in Germany there are signs of the effects of the intersection of two structural trends. Stille also found indications of the time of rise of the German salt masses corresponding with the orogenic periods. Nevertheless, at a later date he felt compelled to concede more importance to isostatic forces in Germany than he had formerly admitted, and was convinced that isostatic phenomena had played a considerable part in the upthrust of salt on the Gulf Coast.

From his study of the Roumanian salt masses Mrazec was of the opinion that they were dependent on the thrusting movements of the Carpathians, but Krejci-Graf has noted certain facts in connexion with the distribution of the intensity of folding, and the times of dying down of folding movements and maximum rates of rise of the salt masses, which seem inconsistent with this view. Krejci-Graf, therefore, has suggested that in Roumania the formation of the upthrusts was initiated by lateral pressure. This also caused the mobile salt to penetrate the overlying more competent beds at the crests of the folds where the resistance was least, whilst the final vertical rise of the extruded core was due to differential loading of the salt. Theoretically, lateral pressure could have accomplished the final stage, but he considered the field evidence to be against it.

Whatever the driving force, the theory of plastic injection of salt readily explains the contortions in the salt, the steeply dipping beds, local unconformities, the presence of radial and peripheral faults, the associated breccias, doming of the covering beds, and the occurrence of surface mounds. It is possible that a rising salt mass, which uplifts the surface sediments while sedimentation is still in progress, may affect the nature of the nearby deposits. The flow of salt from the surrounding areas, especially if the movement is due to differential loading, may be expected to create a peripheral or rim syncline, as has been indicated by Nettleton's experiments [13, 1934]. Rim synclines may increase in strength at depth.

A salt mass will cease to rise if the driving force falls below the critical value or if, due to exhaustion, development of a rim syncline, or other features, the supply of salt is cut off. The existence of rootless salt masses is possible.

In Iran, from density considerations and the elevation of the salt above the surrounding terrain, the depth of the source bed has been estimated on the assumption of isostatic balance. The figure reached is comparable with the depth of the assumed salt source in the Hormuz series, calculated from stratigraphical data. Hence, having regard to the time of rise and the general setting of the Iranian salt plugs, Harrison [8, 1931] suggested that, whilst agglomeration of the salt from an even bed into nuclei was conditioned by tangential pressure, the chief factor in driving the salt upwards was irregularity in overburden or static pressure.

Opinion is divided concerning the cause of the upthrust of salt in Germany. Romanes' [16, 1931] view is that the evidence is against any strong tangential forces having acted on the salt, for the only acute folding is in the immediate vicinity of the salt masses. He believes that folding has guided their distribution, whereas differential loading has supplied the driving force in the uplift. On the other hand, Stille and others claim that tangential pressure has played a prominent part. The tectonic setting of the Roumanian and North African salt masses is complex, and it appears that lateral pressure may have been of more importance than in some other regions. The location of the Gulf Coast salt domes in an essentially unfolded region has led to the wide acceptance of the theory that their uplift is due to differential loading. For the Utah-Colorado salt masses, intrusion contemporaneous with the folding of Late Pennsylvanian and Late Permian age has been suggested [14, 1927], but Harrison attributed much of their growth to differential loading and cited recent river cutting as a cause of the differential [9, 1927].

In many regions until there is a definite proof as to which features are causes and which effects, support may be given to one or the other view concerning the driving forces by inverting the interpretations. Tangential stresses (tensional or compressional) tend to be invoked to explain the distribution and initiation of salt uplifts. In this connexion the structure and weaknesses of the beds immediately above the original salt bed will have a dominating influence, with the result that salt masses may appear in somewhat anomalous positions in relation to the surface geology.

Origin of the Cap-rock

The origin of the cap-rock is a further matter of dispute. In Germany it has been widely accepted that if the salt rises

into the zone of circulating sub-surface waters the soluble materials at the top will be removed, leaving a more or less flat table of anhydrite, gypsum, and clay. Such solution would account for the central depressions over some salt masses, central synclines, grabens, and salt springs. On the other hand, there are geologists in America who maintain that the thickness of the cap-rock on some salt cores is too great to be explained thus, since the salt cores show only a very low percentage of insoluble matter. However, such low percentages are not necessarily a measure of the amount which may have been present in the salt which has been dissolved, assuming that solution is the correct theory. The alternative suggestions offered are that the cap-rock is part of an original sedimentary bed which overlay the salt at depth and has been carried upwards, or that it has been deposited from underground waters.

The broad divisions of the full cap-rock are, in descending order, a zone of calcite ('limestone' cap) and sulphur, a zone of gypsum, and at the base a zone of anhydrite [5, 1926]. The divisions do not consist wholly of these materials, but are merely characterized by the predominance of one of them. Gypsum may be expected to overlie anhydrite if hydration of the latter can only occur under low temperatures and pressures. 'Limestone' and gypsum are not found on the deeper domes [7, 1934], and sulphur has not been recorded in Germany. Cap-rock sulphur is characteristically associated with calcite, and its formation has been attributed to the interaction of calcium sulphate and hydrocarbons. In this reaction calcium carbonate would also be formed which has, however, sometimes been ascribed to infiltering meteoric waters.

The absence of cap-rocks on some salt masses has been attributed to the salt breaking through a developed cap or to the purity of the salt, and attempts have been made to correlate their presence or absence with the depth of the salt. Clearly, if the cap-rock is part of an original covering bed, it will be most likely to be present on the salt masses which have not risen far, whilst if it is formed by solution of salt, its presence or absence will depend on the opportunities for attack by water which have occurred during the whole history of the salt uplift.

The cap-rock commonly shows signs of several periods of brecciation and recementation, possibly due to the removal of supporting salt leading to collapse. The presence of a heavy cap-rock has been given as a possible cause of salt overhang [10, 1932].

The Age of the Salt in the Various Regions

In Germany the salt is of Zechstein age and the main uplifting movements were probably in Lower and Upper Cretaceous times [16, 1931], but they continued at later dates. The problem of the age of the salt in Roumania is not yet settled. Voitesti's interpretation of the materials in the breccias associated with the salt masses is open to grave doubt. This and quantitative considerations led him to lower the source farther and farther down the geological column until he suggested that these, and all other salt masses, arose from salt condensed from a vapour and concentrated by water in depressions on the earth's original crust. Many geologists place the age of the Roumanian salt as Upper Oligocene or Lower Miocene, and that of Transylvania as Miocene. The date of uprise in Roumania was probably Pliocene and later.

In Iran, salt of Lower Fars age has formed only one uplift where salt outcrops, although Lower Fars salt accumulations have been met in drilling. The salt and gypsum of the remaining Iranian salt plugs, together with the associated red beds, probably belong to the Early Cambrian (Hormuz series), for the debris with the salt contains fragments from the Cambrian to the Jurassic. Uplift took place as early as the Upper Cretaceous, but the majority of the plugs rose in Pliocene or post-Pliocene times.

The age of the salt of the Gulf Coast region is by no means settled and, whilst it is probable, it is not certain that it is all of one age. It is at least older than the uppermost Cretaceous [2, 1933], and there is evidence of a source at least as low as the basal Lower Cretaceous for the salt of some of the Interior domes. Some ascribe it to the Permian or Triassic, and fossil algae resembling Permian forms, though unfortunately of long time range, have been found in the salt of the Markham dome. Against a Permian age is Schuchert's contention that the Cretaceous of the Gulf Coast is underlain by pre-Cambrian metamorphics. Anhydrite and red beds have been found in the Lower Cretaceous of north-west Louisiana and north Texas, and Lower Cretaceous salt is reported at Ojinaga, Chihuahua [4, 1926]. Permian and Early Palaeozoic salt is well known some distance outside the salt-dome region. Formation of the domes was in progress as early as Wilcox (Early Eocene) time and must have continued until quite recently [2, 1933]. Harrison [9, 1927] dated the Utah-Colorado salt as Lower Pennsylvanian, but Silurian and Devonian fossils have since been found in shales which appear to have been carried up by the salt [14, 1927].

Relationships between Salt Structures and Oil Accumulations

Although it is possible that some genetic connexion may exist between oil formation and salt structures, the cases where critical examination has been possible have failed to support the idea. Andrussow [6, 1920] noted that the conditions which seem to be involved in the formation of some salt deposits, can lead to the killing of large numbers of organisms, and the organic matter may be transformed to oil in some instances. Furthermore, the earlier phases of salt uplift may have produced shallow-water conditions suitable for the rich development of organisms and may have favoured their conversion into petroleum. However, the only certain relationship is structural—that the salt in arching and uplifting the beds has provided suitable conditions for the concentration of oil into accumulations of commercial importance.

Oil may accumulate in arched beds above the salt, e.g. Humble; in the cap-rock, especially the 'limestone' cap, e.g. Spindletop. Oil production has been obtained from beds abutting against the salt, e.g. Roumania, and on the flanks beneath the overhang, e.g. Barbers Hill. Pinching out of beds due to unconformities or structural thinning will at times control accumulation and, whilst the role of faulting is often difficult to determine on account of the other structural complications, it is certain to provide traps or avenues for migration in some cases. Ritz [15, 1936] has discussed the effects of rim synclines on oil accumulation, and concludes that their strong development may divert oil away from salt-domes and cause it to accumulate on the residual 'highs' formed by interference of the rim synclines.

In particular instances oil may be found at one or more of the sites of accumulation mentioned, and since the oil may be confined to quite a small sector, a large number of wells may be necessary to prove whether or not a given salt structure bears oil.

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OIL ACCUMULATION IN IGNEOUS ROCKS

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SHOWINGS of oil and gas coming from igneous rocks are known in many localities throughout the world. An extensive list of such occurrences will be found in the *Bulletin of the American Association of Petroleum Geologists*, August 1932 [8]. Notwithstanding numerous seepages and showings in wells, only a few localities have yielded commercial production from igneous rocks. The present discussion will be limited to fields which have produced in commercial quantities, the fields discussed being located in Cuba, Mexico, and the United States.

Cuba

In Cuba two fields produce from igneous rocks. One of these fields, the Bacuranao oilfield, is about 10 miles east of Havana. This field is on the northern edge of an outcropping serpentine mass 3½ miles in diameter. The oil is produced from a depth of 200 to 800 ft., and is found in fissures in the serpentine. Sedimentary formations exposed near the field are of Tertiary age. The oil from this field contains much paraffin and has a gravity of 34° Bé., although one well near the northern edge of the field produces oil of gravity 28° Bé. At the close of 1931 the field had produced 112,918 bbl. [6, 1932].

Another field in Cuba, the Motembo oilfield, likewise produces from a serpentine mass which is exposed at the surface, forming a small hill. This field, which is 34 miles east of Cardenas, rises out of flat lands, and the nature and character of the underlying sedimentary formations are not known. The oil is a naphtha produced presumably from fissures in the serpentine which is cut by igneous intrusions. The production is small, the total to the end of 1931 being about 5,000 bbl. The depth of production varies from 285 to 1,905 ft. The gravity of the oil from the deep well was 56° Bé. Some gas accompanies the oil [6, 1932].

Mexico

In the Gulf Coastal Plain of Mexico many oil seepages come to the surface following breaks in the rock caused by igneous intrusions, including igneous plugs, dykes, and sills. As a rule, the igneous rock does not afford storage of the oil in commercial quantities. However, in the Furbero oilfield in Vera Cruz commercial production has been obtained. At this locality a sill of igneous rock, gabbro, has penetrated Tertiary shales and has altered the shale both above and below the sill. Oil is obtained both from the igneous rock and from the metamorphosed shale. The production to the end of 1931 was 1,971,600 bbl., and the field was then producing 183 bbl. per day. With regard to this occurrence, E. De Golyer [5, 1932] says:

> 'The writer sees no particular significance in this exceptional association of oil and igneous rock beyond the fact that the intrusion of the igneous rock from below and its metamorphism of contiguous shales formed a channel for migration from deeply buried oil-bearing beds and a trap for the accumulation of the oil.'

United States

California.

In the State of California oil is found in commercial quantities in igneous rock at one locality, the Conejo Pass oilfield in Ventura County. At this locality the surface rock is igneous, consising of volcanic agglomerate and flows of basalt and andesite. The oil occurs at shallow depths, 60 to 250 ft., being stored in the agglomerate, sheared basalt, or in alluvium overlying igneous rock. Not far north of the field the igneous rock is in fault contact with Tertiary sediments. The oil in this field is heavy, 16° Bé., and contains no gasolene. The production is small, amounting to about ¼ bbl. per well per day.

With regard to the probable source of the oil, Taliaferro [10, 1924] writes as follows:

> 'There are three possible sources for the oil: (1) it may have originated in the Eocene shales below the volcanics; (2) it may have migrated into the fault, and thus into the volcanics, from sands in the Sespe; (3) or it may have come from organic shales interdigitated with the flows and agglomerates. There is no direct evidence as to which of these hypotheses is correct. Small amounts of oil have evidently moved upward along the somewhat porous agglomerates and accumulated in the alluvium which overlies them in the shallow valleys at the edge of the hills.'

Texas.

In the Amarillo region of north-west Texas some oil has been obtained from fissures in granite and from altered and reworked granitic material underlying the oilfields of that region. This oil, obviously, is derived from the adjacent Palaeozoic formations.

In the Coastal Plain region of Texas oil has been found in commercial quantities in igneous rock in four counties, as follows: Bastrop, six fields; Caldwell, four fields; Travis, one field; Williamson, three fields. In all of these fields the igneous rock in which oil is stored lies embedded in Cretaceous formations, the volcanic activity giving rise to the igneous rock having occurred during Cretaceous time. In some instances apparently the lava was erupted in the Cretaceous sea and formed a submarine volcanic cone. Some of the volcanic cones projected above sea-level or were subsequently so elevated as to be exposed and subjected to erosion. Some possibly were entirely submarine. A part of the igneous rock did not reach the surface and is found in the formations in the form of laccoliths, dykes, or sills. Many of the igneous masses in this region, originally embedded in Cretaceous strata, are now exposed. None of the exposed igneous rocks produces oil, and of the embedded igneous masses many are likewise non-productive.

The formations of that part of the coastal region of Texas in which these igneous rocks are found are as follows:

	Uvalde region		Austin region	
	Formation	Thickness ft.	Formation	Thickness ft.
Eocene	Wilcox	350–750	Wilcox	1,000–2,000
	Midway	250	Midway	300–400
Upper Cretaceous	Escondido	500	Navarro	400–600
	Anacacho	300–500	Taylor	600–1,000
	Austin	350–500	Austin	300–400
	Eagle Ford	75–400	Eagle Ford	30–70
Lower Cretaceous	Buda	75–150	Buda	30–60
	Del Rio	75–150	Del Rio	60–90
	Georgetown	30±	Georgetown	70–100
	Edwards	500±	Edwards	300–350
	Comanche Peak	60±	Comanche Peak	40–50
			Walnut	15
	Glen Rose	1,000–3,500	Glen Rose	1,000–2,000
	Travis Peak	100–350	Travis Peak	100–350

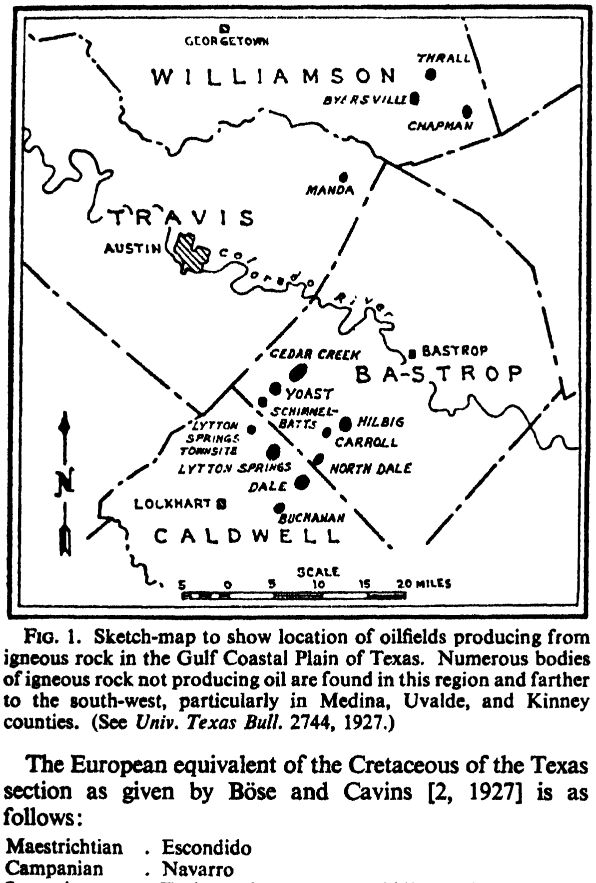

FIG. 1. Sketch-map to show location of oilfields producing from igneous rock in the Gulf Coastal Plain of Texas. Numerous bodies of igneous rock not producing oil are found in this region and farther to the south-west, particularly in Medina, Uvalde, and Kinney counties. (See *Univ. Texas Bull.* 2744, 1927.)

The European equivalent of the Cretaceous of the Texas section as given by Böse and Cavins [2, 1927] is as follows:

Maestrichtian	. Escondido
Campanian	. Navarro
Santonian	. Taylor and Upper and Middle Austin
Coniacian	. Lower Austin
Turonian .	. Upper Eagle Ford
Cenomanian	. Lower Eagle Ford, Buda, Del Rio, and Upper Georgetown
Albian .	. Lower Georgetown, Edwards, Comanche Peak, Walnut, and Glen Rose
Aptian .	. Travis Peak and basal sands

The history of the formation of these storage reservoirs appears to be as follows: Eruption and intrusion of a basaltic igneous rock occurred over an extensive area in Texas in Upper Cretaceous time. Igneous activity occurred intermittently during a long period of time, the igneous material being found in several formations. The eruptions which resulted in the most favourable conditions for storage of oil in commercial quantities were those that occurred during or immediately following deposition of the Austin chalk formation of about mid-Upper Cretaceous time. The igneous rocks became altered and were in part reworked, and, consisting probably of successive flows, they were for the most part highly porous. Subsequently they were engulfed in the next later cycle of Cretaceous sedimentation, the clays and marls of the Taylor formation. The conditions favourable to accumulation of oil in commercial quantities in this region occur chiefly in the Taylor formation, and most of the commercial production in these fields is from igneous rock embedded in this formation.

The depth to these buried igneous masses varies. The Cretaceous and Eocene strata of this part of the State form a south-eastward dipping monocline. The first field discovered, Thrall, produces at a depth of 612 to 950 ft. In other fields farther down the dip the igneous rock lies at a greater depth.

Wells producing from the igneous rock in the Texas Coastal Plain vary greatly, large wells often being adjacent to very small wells. The depth that it is necessary to drill into the igneous rock is likewise variable. The oil is mostly relatively light, gravity 36 to 39° Bé., although oil of much lower gravity is found. The oil is high in paraffin (ozokerite), and in most of the fields is accompanied by relatively little water.

Following eruption the igneous rock underwent alteration and hydration. The unaltered igneous masses consist of basaltic rocks of several varieties including olivine basalt, nephelite basalt, limburgite, gabbro, and phonolite. The altered products of these rocks are commonly referred to as serpentine. Lonsdale [7, 1927], however, has called attention to the fact that the name is not specifically descriptive of the rock. Recently the rock of one of the fields, Hilbig, has been identified by Smiser and Wintermann [9, 1935] as palagonite, a hydrated basic glass. Not only has the original rock altered in place, but at many localities has been more or less reworked and redeposited. The oil is stored in part in the altered igneous rocks and in part in reworked igneous rocks on and around these original cones.

The oil in all of these fields is believed to originate in the Taylor formation, the igneous masses serving only as storage reservoirs. The irregularly distributed, although often high, porosity of these volcanic rocks results from their accumulation as massive flows, the igneous masses being chiefly altered tuffs.

Bastrop County.

The commercial producing fields in Bastrop County are Cedar Creek (including North Cedar Creek), Carroll, Hilbig, North Dale, Schimmel-Batts, and Yost. To the end of 1934 these fields had produced a total of 1,765,001 bbl. of oil, of which the Yost field had produced 819,293 bbl. and the Hilbig field, 510,583 bbl. Each of the fields is a small igneous cone, embedded in Cretaceous strata, chiefly in the Taylor formation. The bases of the cones rest either in or on the Austin formation, although for each igneous mass there is presumably a neck or vent extending downwards. The Austin formation may in some instances slightly overlap the sides of the igneous rock. Such is reported to be the condition in the Hilbig field and, if true, indicates extrusion of the lava of this field somewhat before the close of the deposition of the Austin formation.

Yost was the first of these fields discovered, 1928,

and is now practically exhausted. The Hilbig field, discovered in 1933, which is being developed as a unit, will undoubtedly yield a much larger ultimate production than the Yost field.

Caldwell County.

The commercial producing fields from igneous rock in Caldwell County are Buchanan, Dale, Lytton Springs, and Lytton Springs townsite. The production from these fields to the end of 1934 was 9,129,500 bbl. This total comes chiefly from Lytton Springs field, 7,782,319 bbl., and from Dale field, 1,185,460 bbl.

The character of the igneous rock and its place in the Cretaceous section in these fields is similar to that of the fields in Bastrop County. The Lytton Springs field, the largest and most carefully studied of the fields of this county, has a producing area of about 1,385 acres. The oil, gravity 38° Bé., contains much paraffin. The igneous mass is oval in shape, being slightly elongated north–south, its dimensions being approximately 9,500 by 9,000 ft. The igneous cone is flat topped with steep sides. From the crest the slope, aside from minor irregularities, is gradual in all directions for distances ranging from 2,500 to 4,000 ft., beyond which it is abrupt. The difference in elevation from a high point on the crest to the lowest point that can be measured on the margin is 500 or 600 ft. The igneous rock lies near the base of the Taylor formation. It rests directly on the Austin chalk in part of the field and, in places, takes the place of the chalk. However, Bybee and Short [3, 1925] have shown that in a well near the margin of the field part of the Taylor marl underlies the igneous rock. The known thickness of the igneous rock ranges from more than 500 ft. in the central part of the field to a few feet or almost nothing at the margins. A slight structural dome at the surface overlies the igneous mass. At the crest of the dome, according to Collingwood and Rettger [4, 1926], the Lower Midway formation is exposed surrounded by Middle and Upper Midway.

Considerable faulting occurs near the dome. One fault, seen at the surface south of the field, trends north-east directly towards, and possibly into, the field.

Travis and Williamson Counties.

The one small field discovered in Travis County, the Manda field, has produced only a few hundred barrels of oil. In Williamson County three fields have been developed, Byersville, Chapman, and Thrall. The total production from these fields to the end of 1934 was 6,097,847 bbl.

The Thrall field, discovered in 1915, was the first field to produce from igneous rock. Although nearly depleted, this field is still producing in a small way, its total production to the end of 1934 having been 2,353,962 bbl. The igneous mass is somewhat irregular in outline, being about 4,800 ft. in extent east–west and 5,000 ft. north–south. The slope from the flat-topped crest is at first steep and then more gentle. The steepest slope is about 275 ft. in one-third of a mile. The producing area of the field is 473 acres. The gravity of the oil is 39° Bé.

The igneous rock lies within the Taylor marl, many well logs showing 200–300 ft. of Taylor marl under it. However, in a well assumed to be near the vent through which the igneous rock came, only 10 ft. of Taylor marl intervenes between the igneous rock and the Austin formation.

Immediately overlying the igneous rock is a thin stratum referred to by the driller as 'cap-rock'. In the north-eastern half of the field this rock consists very largely of a porous shell breccia. Towards the south-west the 'cap' consists of clay or marls with some compact limestone. This rock, in the opinion of Udden and Bybee [11, 1916], indicates that the igneous rock was extruded into the Taylor sea; subsequently the shell breccia formed on the flank which was more directly exposed to wave action, and marl and limestone on the side less exposed.

The Chapman field has been more productive, having produced 3,707,385 bbl. from its discovery in January 1930 to the end of 1934. The total producing area is 476 acres. The gravity of the oil is 37 to 38° Bé.

The igneous mass of this field, as shown by the accompanying contour map, is approximately circular or with a slight north–south elongation, being about 4,000 ft. wide and 5,500 ft. long. The maximum difference in elevation from the crest to the margins of the dome is about 400 ft. The steepest slope is towards the north-east. Faulting is not definitely recognized in this field. Only a little water has been found. The initial production of oil varies from a few barrels to more than 5,000 bbl. Large and small wells are irregularly distributed. It is difficult to determine from the logs where productive strata are located in the wells, but they are apparently at varying depths in the igneous rock. Wells drilled through the rock indicate that its thickness varies from 525 ft. in the centre to a few inches at the margins.

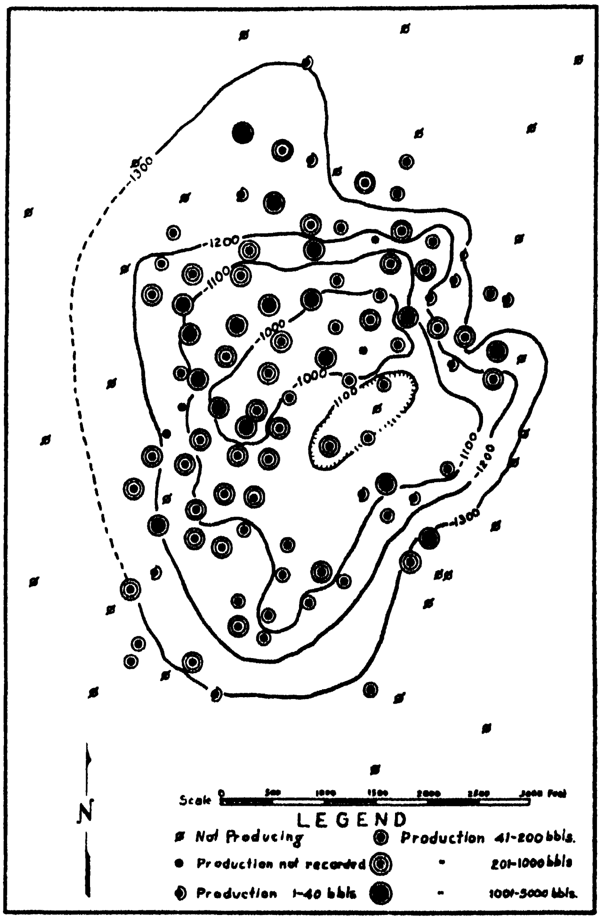

FIG. 2. Contour map of the Chapman oilfield contoured on top of the igneous rock. Contour interval 100 ft. The approximate initial production of wells is indicated by symbols as shown in the legend. This and the following illustration are adapted from illustrations made by the author and used in *Bull. Amer. Assoc. Petrol. Geol.* **16**, 748 and 749 (1932).

The igneous rock lies within but close to the base of the Taylor formation. Most of the wells drilled through the igneous rock in the central part of the field enter the Austin chalk with no intervening marl, but in wells near the margin the drillers usually log gumbo, shale, and marl between the igneous rock and chalk. In the absence of cores it is difficult to check these logs, since, as is well known, the soft igneous rock drills like gumbo and shale. However, a sample was obtained from Westbrook's M. D. Lawrence No. 8 directly under the igneous rock, depth 1,740 to 1,760 ft., which consists of fossiliferous brown shale probably of Taylor age. The records thus indicate that although the igneous rock rests on Austin chalk in the central part of the field, in some places, particularly near the margins, part of the Taylor marl intervenes between the igneous rock and the Austin chalk. The igneous rock is, therefore, a flattened oval mass lying chiefly within the Taylor formation, but with a part of the base resting on the Austin chalk. An east–west section through the dome is shown in the accompanying figure.

Not all of the oil of this field is produced from the igneous rock. A thin stratum of limestone, probably similar to that at the west side of the Thrall oilfield, overlies the igneous rock, and several of the wells are productive from this horizon. A contour map at this horizon indicates doming in this limestone, probably somewhat less in amount than the relief on the top of the igneous rock. The apparent doming of the chalk stratum overlying the igneous rock may be incidental to the presence of the dome at the time the chalk was being formed.

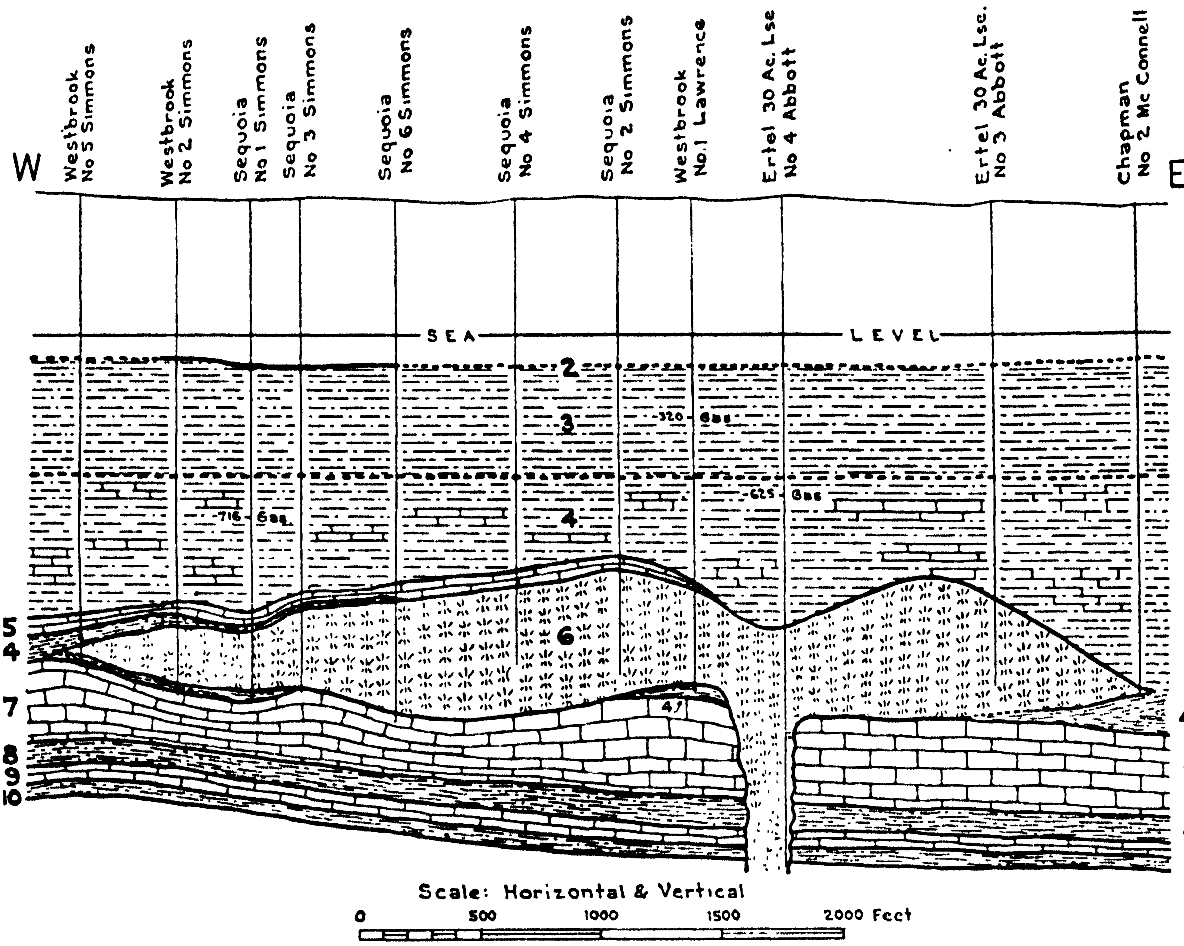

FIG. 3. Section through the Chapman oilfield showing relationship of igneous rock to overlying and underlying formations. 1, Tertiary formations, Wilcox and Midway; 2, Greensand horizon, probably at base of Midway; 3–10, Cretaceous formations as follows: 3, Navarro; 4, Taylor; 5, chalk stratum near base of Taylor; 6, igneous rock from which oil is obtained; 7, Austin; 8, Eagle Ford; 9, Buda; 10, Del Rio. One of the wells, Ertel No. 4 Abbott, penetrated 954 ft. of igneous rock, depth 1,666 to 2,260. This well apparently is located in the opening through which the igneous rock was extruded.

It seems probable that the lava flow forming this cone occurred in early Taylor time and was probably subaqueous, as indicated by the relative flatness of the igneous mass.

In conclusion, there is no evidence that the oil originated in igneous rock. On the contrary, all of the occurrences described in this paper on which there is reliable evidence support the conclusion that the oil without exception has originated in sedimentary rocks and has migrated into the nearby igneous rocks which serve only as a storage reservoir.

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SECTION 7

GEOLOGICAL METHODS OF EXPLORATION

HISTORICAL NOTES ON THE DEVELOPMENT OF THE TECHNIQUE OF PROSPECTING FOR PETROLEUM

By E. De Golyer, A.B., Sc.D., F.G.S.

Introduction

The Drake well, completed on 29 August 1859, at Oil Creek, Pennsylvania, is commonly accepted as marking the beginning of the petroleum industry in the United States, if not in the entire world. This well, 69 ft. deep and with an initial production of only some 25 bbl. daily by pumping, is unimpressive enough in itself and important only because of the train of consequences which followed.

The petroleums were no new thing. They have a history of usefulness to man running back into the mists of antiquity and long antedating the establishment of the modern industry. Asphalt and bitumens were used as a cement in building the walls of Babylon, and were an article of commerce among the ancient Mexicans. Liquid petroleum, collected from springs, was used as a medicine both internally and externally by many primitive peoples, and was used as a lamp oil in Italy and China before the beginning of the Christian era. Flares from burning gas and oil springs were strange and impressive phenomena having a place in the religious rites of the ancient Iranians, Israelites, Egyptians, and Greeks, and formed the central mystery around which grew up that strange sect, the fire-worshippers of Baku.

Successful wells, purposely drilled for natural gas, had been completed near Fredonia, New York, as early as 1821. Petroleum in quantities great enough to defeat the purpose for which they had been drilled was commonly encountered in brine-wells for half a century before the Drake well. Many of these wells produced petroleum and gas in considerable quantities, a notable example being the famous 'American Well', drilled for brine in 1829 to a depth of 180 ft. on Rennix Creek, Cumberland County, Kentucky. This well flowed by heads, at intervals of 2 to 5 minutes, for 3 or 4 weeks, and then flowed steadily 'many thousands of gallons per day'.

Time was ripe for the establishment of a petroleum industry in the 1850's. The sperm-whale fisheries had passed their zenith in the late 1840's and were on a decline. Sperm oil, the prime illuminant, in the face of this decline in production and constantly increasing consumption, was becoming more expensive. Substitutes were being sought. By 1859 some considerable success was being had in the production of 'coal-oil', oil distilled from coal or shale, and already the suitability for lamp oil of the products derived by the distillation of crude petroleum had been demonstrated.

The only question with regard to petroleum as a suitable raw material from which to manufacture lamp oil and lubricants was the all-important one of quantity. This question was answered with an emphatic affirmative by the developments which followed upon the completion of the Drake well.

For almost half a century the petroleum industry continued chiefly as a supplier of lamp and lubricating oils. During the first decade of the present century, fuel oil became an important product. For almost all the last quarter-century, and at present, gasoline has been, and is, its most important product.

The Problem of Prospecting

The two essential preliminary steps involved in the discovery of a pool of petroleum or natural gas—in successful exploration or wild-catting—are, first, the selection of a suitable site for the prospect well and, second, the proper drilling of such well.

The selection of a suitable site for the well may be accomplished by casual and random location, by accident, and on the basis of incorrect conclusions and misunderstanding. Indeed, it is remarkable how many great pools have been discovered in such manner. The prospect wells themselves have at times been worried to successful completion by entirely inadequate and badly handled equipment. These are lucky accidents, however—the romantic discoveries which have their parallel in almost every mineral industry. We are concerned with the best practice rather than some spectacularly happy result which may attend the worst practice.

The science of prospecting has been more highly developed in the petroleum industry than in any other mineral industry. This condition is the result of the necessity imposed by the exceedingly high rate of consumption of petroleum and its products. The entire production of the States of Pennsylvania and New York since the beginning of the industry is hardly more than enough to satisfy the current requirements of the United States for a single year. All the oil yet produced in the eastern fields of the United States would hardly suffice for three years. We consume at the rate of six to eight Humbles or Spindletops, two to three Salt Creeks, Cushings, Coalingas, or Santa Fe Springs per year. No single pool has yet produced a total of oil sufficient to satisfy our current consumption requirements for one year, and only one field—East Texas—gives evidence of being able to break this record. Obviously, an industry subject to such tremendous demands must develop every possible skill in prospecting for new deposits.

The Drake well was drilled because of nearby oil-springs, by men whose entire knowledge of the occurrence of petroleum could have been only that it could sometimes be skimmed from the flow of springs, that the exceedingly low rate of production from springs could often be increased by digging pits or trenches, that petroleum could sometimes be found impregnating rock outcrops, that it was often found—at times in quantities great enough to make it a nuisance—in wells drilled for brine, and that it might be associated with natural gas-springs. The successful completion of this well after months of wearisome effort, at the shallow depth of 69 ft., marks the beginning of successful prospecting for petroleum. The successful completion at a depth of 9,572 ft., in 1935, of the discovery well of the Lafitte pool, Louisiana, at a site in the flat swampy delta of the Mississippi River, selected as a result of the mapping of a suitable structure by the reflection method of seismic survey, is an outstanding example of the best modern practice in prospecting.

The modern science of oil prospecting has developed within the three-quarters of a century which have passed since the completion of the Drake well; for the most part

it has developed during the past quarter-century—the period when the demand for gasoline has put such pressure on the industry.

The selection of a proper site for a test well, in best modern practice, has become the business of the geologist. He early recognized the fact that most oil-pools occur in sedimentary rocks lying in folds of anticlinal type. With the study of hundreds of oil-pools, he recognized variations and modified his simple anticlinal theory, first into the more inclusive structural theory, and later, with some understanding of the fewer cases in which stratigraphic variation alone or principally may achieve a similar effect, into the trap theory.

The technique of geological work has improved substantially, particularly within the last decade. Starting with surface structural work, mapped with clinometer or by the distribution of formation outcrops, achieving further structure-finding ability through subsurface studies, and particularly after the introduction of micro-palaeontology as an aid and a control, it progressed to core drilling for structure and finally, with notable success, to the use of geophysical methods for structure finding.

The drilling of the test well has been, and is, the business of the driller and of the engineer. Constantly improving ability to drill quickly and cheaply to ever greater depths has been one of the most notable advances in drilling technique, culminating, for the moment, in the notable Gulf McElroy well No. 103, drilled to the record-breaking depth of 12,786 ft. Oklahoma City and Kettleman Hills are outstanding examples of major pools which had been recognized as favourable prospects and drilled, but which had to await this extension of ability to drill to deeper horizons before they could be successfully explored. An improvement in ability to test and secure pertinent information from the formations penetrated, as a result of improvements in coring practice, drill-stem testing, and electrical logging, has been hardly less important, as an aid to prospecting, than the increasing ability to drill deeper.

Location of Site for Test Well

The first commonly accepted guide to the location of test wells was the occurrence of direct indications—oil-springs, gas seeps, asphalt, oil-impregnated rocks, or oil-shows in wells drilled for other purposes. Most of the important oil regions and many of the great oil-pools of the world were prospected first of all because of the common occurrence of direct indications. Even a cursory review shows that this was true for Canada, Pennsylvania, West Virginia, Kentucky, Ohio, Indiana, Texas, Louisiana, Oklahoma, Kansas, Wyoming, California, Mexico, Trinidad, Peru, Columbia, Venezuela, Russia, Roumania, Poland, Persia, Borneo, Sumatra, and Java. Several great oil enterprises owe their initiation to the faith inspired by the occurrence of marked or abundant direct indications, notable examples being the Doheney and Pearson operations in Mexico and the Anglo-Iranian operations in Iran.

There is a notable tendency among modern geologists to neglect and undervalue such direct indications. It may be admitted that the direct indications are chiefly of value as positive evidence of the petroliferous character of the rock section of a particular region, and that, once such condition is definitely established by the development of oil-pools, the existence of direct indications on any specific prospect is of much less importance than in an altogether untested region.

As more pools were outlined, a crude technique of prospecting began to develop empirically. At its best, prospecting of this period was guided by vague and ill-defined geological considerations, not recognized as such by the prospector. Trend lines—lines established for any particular region by the strike of the major axes of pools already developed or by lines connecting developed pools and, when real, generally coincident with the geologic grain of the region—had great vogue in Pennsylvania and were useful as late as the early development of Oklahoma. Topographic resemblance, when effective generally a reflection of structure, had great vogue among unsophisticated prospectors. This clue was sound and was extremely useful for the earlier developers of the Texas and Louisiana coast.

These early gropings of untrained prospectors towards some understanding of the habits of occurrence of the mineral which they were seeking suggest that if the science of geology, then in its infancy and just emerging from the broad fields of natural philosophy and mining, had not been ready at hand for use when the time came, the industry would have developed a geological science, particularly the branches of stratigraphy and structure, for itself.

The first and by far the most important step towards the development of a rational technique of prospecting was the acceptance of geology as a guide by the industry. The production of oil had hardly started before the habits of its occurrence began to be studied by geologists.

Within nine months after the completion of the Drake well, Henry D. Rogers, then Regius Professor of Natural History at the University of Glasgow, State Geologist of New Jersey 1835–40 and of Pennsylvania 1846–58, and the leading structural geologist of his time, noted that the newly discovered oilfields were located on anticlines.

The first clear statement of the anticlinal theory, however, was made in 1861, in a public address at Montreal by T. Sterry Hunt, a brilliant but erratic chemist and geologist, then chemist in the Canadian Geological Survey and afterwards assistant on the Second Pennsylvania Survey. In 1865 Hunt elaborated his beliefs to the effect that oil was formed chiefly in limestones and black shales, that it was liberated by folding and fracturing which occurred chiefly along the axes of anticlines, and that it rose and accumulated along the crowns of anticlines as a result of being lighter than the water with which it was associated.

It is remarkable how clear, comprehensive, and workable a theory of petroleum origin, accumulation, and occurrence was thought out and published by T. Sterry Hunt at this early date, and how little advance in theory, except for elaborations and amendments growing out of almost three-quarters of a century of experience, has been made since his time. A modern reasonably competent geologist, with no special training in petroleum geology beyond the writings of Dr. Hunt as a text, would not be altogether inadequately trained for prospecting even to-day.

Within 8 months after the initial announcement of the anticlinal theory by Hunt, E. B. Andrews, then Professor of Geology at Marietta College, Ohio, and afterwards Assistant Geologist to the Ohio State Survey under Newberry, noted the occurrence of oil along the Volcano anticline—the 'Oil Break'—in West Virginia and Ohio, and published his conclusions describing the anticlinal occurrence of the oil and oil-springs, but apparently regarding fissures as the factor controlling accumulation and the anticline of importance only because its axis might be a likely locus for fissures.

Andrews belonged to that important and extensive school of the early days of the industry which regarded fissures in the containing rock as essential to account for the

occurrence of important accumulations of petroleum, and which failed to recognize the quantitative sufficiency for such purpose of the pore space in ordinary sandstones.

The common belief in the importance of crevices and fissures was so great that a 'crevice finder' was invented and wells were explored with it for several years to the profit of its operators.

The 'fissurites' died but slowly, though Alexander Winchell, sometime Professor of Civil Engineering and later of Geology, Zoology, and Botany in the University of Michigan, State Geologist of Michigan 1859–61 and again in 1869–71, and one of the most popular writers and lecturers on geology of his day, had suggested as early as 1860 that sandstones themselves were sufficiently porous to contain oil, even without fracturing, and John F. Carll, oil expert to the Second Pennsylvania Survey, showed that the normal porosity of sandstone was great enough to account for the most productive wells yet discovered.

Henry D. Rogers, in 1863, in a paper notable chiefly for its clear statement at so early a date of the fundamental principles of the carbon ratio theory, afterwards rediscovered and applied by David White, notes additional evidence favouring the anticlinal theory.

Hunt, in his early writing, showed a remarkable understanding, for so early a time, of the function of gas in the production of oil, and a Mr. Briggs, in 1865, suggested that oil-wells flow because 'Petroleum is an intimate mechanical mixture of the gases into which petroleum decomposes, with the petroleum fluid, like that which exists between the carbonic acid and the water in a soda fountain.'

Various other geologists during this early period of speculation published theories and comments essentially in the nature of those by the authors mentioned, but geology was little used, if at all, in the actual business of prospecting. The validity of the anticlinal theory was not accepted unanimously even by geologists themselves. The emotional, energetic, sometimes pessimistic, and always caustic J. Peter Lesley, topographer on the First Pennsylvania Survey, one time Congregational minister, Professor of Geology in the University of Pennsylvania, and head of the Second Geological Survey of Pennsylvania (1874–88), attacked it often and with vigour. His opposition, as the head of the official survey of the then most important oil-producing State in the world, must have done much to delay the acceptance of the theory by the industry.

The Canadian, West Virginia, Ohio, and Indiana surveys stood definitely for the theory of anticlinal accumulation; the Pennsylvania survey, under Lesley's direction, stood definitely and bitterly against it. This is the more surprising, since the anticlinal occurrence of oil had already been noted by Lesley's eminent predecessor, H. D. Rogers, and the roster of assistants on his own survey included the names of T. Sterry Hunt, discoverer of the theory, and I. C. White, who by his application and championship of the theory has indelibly associated his name with it.

Hans Höfer, the eminent Austrian geologist whose name is often linked with those of Hunt and Andrews as discoverers of the anticlinal theory, in 1876 published the conclusions resulting from a visit to America in which he called attention to the fact that in Canada, Ohio, and West Virginia the greater quantity of the oil occurs on the anticlines.

I. C. White, the father of the anticlinal theory, was an assistant on the Second Geological Survey of Pennsylvania under Lesley from 1875 to 1884, engaged chiefly in palaeontological and stratigraphical investigations. Early in 1883 he was approached by William A. Earseman, a veteran oil operator then in the employ of the Anchor Oil Company, who had noted the occurrence of many of the great gas-wells of Pennsylvania along anticlinal axes as shown on maps of the State Geological Survey of Pennsylvania, and who had enlisted the financial support of J. J. Vandergrift, President of the Forest Oil Company, for a geological investigation of the occurrence of natural gas. White spent the month of June 1883 in visiting and studying the geological surroundings of all the great gas-wells that had been struck in the Appalachian district. In this work he was often accompanied by Earseman, and the conclusion which was expressed in his report to Vandergrift, at the close of his examination, was that 'the rock disturbance caused by anticlinal waves was the main and important factor in the occurrence of both petroleum and natural gas'. The hypothesis was verified during the next 2 years by the successful location of the Grapeville, Washington, and Belleveron fields, and in 1885 the theory was published.

The importance of White's work is that it was apparently the first field investigation on a broad enough scale to justify generalization, that he made practical proof of the resulting theory, and that, with the aid of other geologists, among the foremost being Edward Orton of Ohio, he successfully defended it against the renewed attack of Lesley and the opposition of Carll, Ashburner, and Chance, all of the Second Pennsylvania Survey.

White's own modest statement and probably his last statement of his position as a discoverer and applier of the theory is as follows:

> 'As you are aware, I was the first petroleum geologist, although Hunt, Andrews, and Höfer had preceded me, in suggesting the anticlinal theory for the accumulation of oil and gas. Their publications, however, were unknown to me, and the discovery was original so far as I was concerned. However, none of the three did anything to put their discoveries into practical operation. I was the first one to do that and demonstrate the truth of the structural theory for the accumulation of oil and gas by going into the field and actually making successful locations on structure.' (I. C. White to E. De Golyer, 4 February 1925.)

Notwithstanding White's brilliant demonstration of the value of the structural theory, the oil industry ran on for another 30 years without much more than sporadic attempts to utilize it. For the United States, this is not surprising. The petroleum resources of the nation were enormous and almost untouched. Drilling was to shallow depths and comparatively cheap. Enough oil was found by ordinary hit-or-miss wild-catting to result in temporary but frequently recurring periods of over-production and consequent market demoralization. There was no economic necessity for improved methods of prospecting, and the industry was not concerned about them.

Among the earliest sustained efforts to organize geological work as an aid to prospecting were probably those in foreign fields, notably the Dutch in the East Indies and the English in Mexico. The late Edwin T. Dumble joined the Southern Pacific Companies as a geologist in 1897, and W. W. Orcutt the Union Oil Company of California in 1898. The organizations founded by these two pioneers are probably the two oldest geological departments having to do with oil which exist in the United States to-day. A. C. Veatch was geologist to the Houston Oil Company for a short period in 1901–2.

The reports and publications of the United States Geological Survey since an early date have contained occasional important papers dealing with the geology of oilfields, but from about 1907 to 1915 an exceptionally important series of reports on the geology of oil-producing areas scattered from Pennsylvania to California were published. Any unprejudiced consideration of this series of reports revealed such evidence of the structural occurrence of the petroleums as could not fail to convince, and this broad demonstration of the possible value of geology as a guide to prospecting was undoubtedly important in bringing about its use by the oil industry.

These surveys at least convinced the geologists who made them. W. T. Griswold left the Survey for consulting work in oil in 1907. Frederick G. Clapp, Ralph Arnold, and Cassius A. Fisher left for the same purpose in 1908. C. W. Hayes, C. W. Washburne, E. B. Hopkins, and the writer joined the geological staff of the Mexican Eagle Oil Company in 1909.

Among other early American petroleum geologists in commercial work were H. B. Goodrich, who examined the oil possibilities of New Brunswick in 1899–1900, reported on Spindletop and other coastal fields in 1900, on the Ebano field of Mexico in 1902, and located the Wheeler field in southern Oklahoma in 1904, Roswell H. Johnson, who was a consulting geologist in Oklahoma from 1908 to 1912, Charles N. Gould, L. L. Hutchinson, Julius Fohs, W. E. Wrather, James F. Gardner, William Kennedy, Lee Hager, W. F. Cummins, E. W. McCrary, W. S. Vandruff, R. E. Vandruff, and F. J. Carmen. Among foreign geologists early in the petroleum industry were P. C. A. Stewart, T. G. Madgwick, F. W. Moon, Leonard V. Dalton, W. H. Dalton, F. Laurie, G. Jeffreys, Max Muhlberg, and F. Zuber.

The period from 1900 to about 1915 was a period when geology was winning its way into the industry. By 1915 a geological department was the rule rather than the exception in a well-organized oil company. By this time the necessity for increased production and reserves imposed upon the industry by the rapidly increasing use of automobiles and the demands of the Great War had forced it to seek improvement in its prospecting technique.

Improvement in the technique of prospecting, in so far as the selection of a proper site for the test well is concerned, has, since the general acceptance of geology as a guide, become entirely a matter of improvement in geological method and in the geologist's ability to interpret his results.

Development of Geological Technique

The geologist, as a prospector, has always been chiefly a structure hunter. Three methods of finding structure have been developed: by surface mapping, by subsurface studies, and by geophysical methods.

The earliest successful surface mapping for oil prospecting was probably that done by I. C. White, who determined the relative elevations of the outcrop of his key-bed by running a line of spirit-levels. Most of the early work was done by mapping the dip and strike of occasional outcrops with a hand clinometer. Another early method was the simple mapping of the distribution of outcropping formations.

The plane table, which had long been in use by topographers and engineers, was probably first used in the Cadiz, Ohio, quadrangle in 1901 by W. T. Griswold, who as a topographer had been mapping the quadrangle. It was being used by geologists of the U.S. Geological Survey in mapping the public lands of the Western States for coal classification as early as 1906, also it was used by geologists working in Mexico as early as 1909, and was commonly used in Oklahoma in 1913.

The next and latest refinement in surface mapping was the introduction of aeroplane photography about 1920, after the close of the Great War. Aerial photographs record 'all and more than the eye can see'. To the geologist they are important as providing, rapidly and economically, accurate base maps containing a wealth of detail not obtainable by any other method. The camera, as a primary geological instrument, records with such precise fidelity and in such detail physiographical features such as hills, drainage sources, &c., that even stream patterns give clues to the existence of faults and structures—clues that often can be verified by field examinations. It also discriminates between colour values beyond the power of the eye, and often records them clearly enough to indicate the distribution of formations, and so structure. Unfortunately, for many of the oil regions which have already been studied in great detail, much of the geological value of aerial photographs is no longer important, since the structures having surface expression have already been found by less detailed and cruder but effective methods of mapping. The Rancherias gasfield in northern Mexico was first found by aerial reconnaissance, and the Cuevitas field in Starr County, and the O'Conner field, Texas, were indicated for further examination by aerial photographs.

Crude subsurface studies are almost as old as the oil industry, but their first systematic and comprehensive use in petroleum geology probably began with the organization of a subsurface branch of the geological department of the Empire Companies about 1917 by A. W. McCoy. Subsurface studies not only afford clues as to structure, but give information as to stratigraphical variation, the nature, extent, and distribution of sands and formations, the existence and extent of unconformities, information as to convergence, and generally are of essential importance to a proper interpretation of surface studies as well as in their own field.

The basis for most subsurface work is correlation, and the earlier work was crude indeed since it rested on no sounder basis than the driller's log. This was soon corrected to some degree by the collection and examination of samples. Real progress came with the introduction, about 1920 by the late Edwin T. Dumble, of micro-palaeontology as a guide to the determination of the age and stratigraphical position of well cuttings. Coincidentally with the development of micro-palaeontological determination came the introduction of the double-core barrel, improved coring practice, the use of heavy minerals as indices for correlation, and improved correlation as a result of detailed examination, on the basis of lithology alone.

The latest and one of the most important aids to correlation has been the increasing use within the last few years of electric logs.

Belonging properly to subsurface studies, but occupying a place between the study of well logs and surface mapping, are pit-digging for geological information and core-drilling for structure.

The digging of a test pit for purposes of geological examination is essentially an attempt to create artificially a geological exposure. It is a special form of trenching, one of the favourite methods of the mining prospector and engineer, and older than the petroleum industry. The

method was used extensively and successfully in the Dutch East Indies by geologists of the Royal Dutch-Shell group. The ratio of successful prospect wells to dry holes as a result of this work was very great and justified the cost of actually digging the geology out of the ground, but it may well be that the high ratio of success was in large part due to the exactness with which a structure could be mapped. The method was used extensively in the Isthmus of Tehuantepec for several years from 1916. Otherwise it has been but seldom used in North America. It is suitable for extensive use in areas of few rock exposures, soft rocks, and low labour costs. It can be used under other conditions only at critical points and where the information desired is important enough to justify the cost. It is important historically because it is the first method used by the petroleum geologist to secure reliable geological information at points important to his work rather than where it might be naturally available.

Core-drilling for structure was recommended as early as 1917 by George E. Burton, who pointed out that the possibility of finding additional structures by surface work in Oklahoma was pretty well exhausted.

Dr. W. A. J. M. van der Gracht, who used the diamond drill with great success as an exploratory tool in Holland, 1905–15, and who had directed its use in a search for structure in Roumania before 1914, introduced its use into the United States in 1919. During the same year M. M. Travis, formerly of the Mid-Continent Petroleum Company, introduced it independently to check supposed anticlines on the Chilocco Indian Reservation, Oklahoma.

The first notable success for core-drilling was the discovery of the north extension and most prolific part of the Tonkawa Pool, Oklahoma, in mid-1922. Early discoveries by the method include the Thomas, Hunniwell, North Braman, Hubbard, and Deep Rock pools of Oklahoma, the Padgett gas-pool and Graham oil-pool of Kansas. The use of core drills increased until 1925, when as many as 50 separate machines were drilling for structure in the Mid-Continent region alone.

The third and most recently accepted group of methods for mapping geological structure are the geophysical methods, of which four, the magnetic, gravimetric, electrical, and seismic, have been used with some degree of success for oil prospecting.

The first of the methods to be used in the oil industry was that of gravity surveys by the use of the Eötvös torsion balance. The possibility of making gravity observations with a torsion balance was outlined as early as 1888 by the late Baron Roland von Eötvös, Professor of Physics in the University of Budapest. The first instrument was completed in 1890. A period of testing in the field and modification of the original design of instrument ensued. Field investigations on a substantial scale began in 1901 on the ice of Lake Balaton, and were soon extended into the Great Hungarian plain.

Eötvös realized and demonstrated the possibility of interpreting buried regional geological structure from a consideration of gravity anomalies, but his interests were entirely in the fields of geodesy and physics. The more definite understanding of the usefulness of the instrument as a geological tool was the realization of Hugo V. Boeckh, late director of the Hungarian Geological Survey, who in 1917 first called attention to the fact that anticlines and domes with light or heavy cores could be located by means of torsion-balance surveys, citing surveys and the existence of such anticlines at Gbely (Egbell). In 1918 Schweydar, with the advice of Boeckh, used the balance to delineate the boundaries of an explored salt deposit in Germany.

The torsion balance was taken up for use in petroleum geology about 1920, the pioneers being the Royal Dutch-Shell and Anglo-Iranian groups. The first survey known to the writer is that of the Hurghada field in Egypt, made in late 1921 or early 1922.

The first torsion-balance survey made in the United States is believed to have been a survey of the Spindletop, Texas, salt-dome in early December 1922. The first salt-dome or field to be found by the method was the Nash, Texas, dome, proved as a salt-dome in November 1924, and as oil-bearing in early January 1926. This was the first discovery by geophysical methods in the United States and probably the first in the world.

The seismograph, which Dr. L. Mintrop of Germany and Karcher, Haseman, Eckhart, and McCollom had been using since 1919 in an attempt to delineate subsurface structure, was used in Mexico and in the Mexia fault-line region of Texas in 1923, but without success. It was brought into the Gulf Coast region of Texas early in 1924 by the Marland Oil Company, locally under the direction of Alexander Deussen, and was soon taken up by the Gulf Production Company at the instance of L. P. Garret.

It proved successful in the location of hitherto undiscovered salt-domes, by use of the refraction method.

J. C. Karcher, who directed the Geophysical Research Corporation, improved the refraction technique considerably. He introduced the radio time-break, sound surveying, and electrical recording. He also developed the reflection method, successfully mapped structure in 1927, and the work had been checked conclusively and with fortunate practical results in 1930. About 1929 the dip method of reflection surveying was developed and is now in general use on the Gulf Coast.

While the magnetic is the oldest of geophysical methods, having an ancient and honourable history in the discovery of iron ore, its value in the petroleum field is not great, and its use which at one time, about 1924, reached considerable proportions is now somewhat limited.

The electrical methods which were introduced into the petroleum industry about 1924 had but a short and experimental vogue. They were successful to a degree, but could not compete with the other methods as prospecting tools.

Such, in brief, is a bare outline of the most important improvements in the technique of geological work in oil prospecting. Improvement in ability to interpret geological data for the purpose of prospecting is a more intangible and less definite matter. The record of the geologist in pioneering new types of structure or in opening up new petroliferous provinces is not good. In both of these highly speculative and hazardous types of enterprise he has usually followed the more daring and adventurous 'wild-catter'. His greatest success as a prospector has been in hunting for new and similar structures, once a new type had been proved. His greatest service to his client, to within recent years, has probably been to point out the likely direction and extent for a newly discovered pool.

The science of petroleum geology, which serves as a base for our prospecting technique, covers a broad field of speculation regarding the origin and migration of the petroleums. While the solution of these vexing problems would be interesting and would advance in some degree our ability to find oil-pools, they are by no means essential to successful prospecting, as is proved by present practices and the present state of the industry. We have a working

theory of the origin of petroleum, accepted generally enough perhaps to be regarded as orthodox, but, on the other hand, certain able, scientific, and skilful geologists hold views divergent enough to be regarded as heretical if they were fully and publicly stated. Even our foremost students of the subject of origin regard none of the hypotheses as absolutely demonstrated, and if the whole field of this subject were to be subjected to the same type of searching scepticism with which, for example, the anthropologist and palaeontologist test a new discovery of fossil man, we would have to admit that our actual knowledge is meagre. So it is with the question of migration. Leaders in the profession of petroleum geology hold for short migration. Equally competent men hold, with equal tenacity, for long migration. Specialists on origin say: 'Once the problem of migration is solved, we can solve that of origin.' Students of migration can solve their problem easily if that of origin is settled.

The firm rock upon which the whole structure of scientific prospecting is based, however, is that of our knowledge of the habits of occurrence of petroleum accumulations. We know from experience that oil-pools occur in rock traps, generally of structural origin, and we are engaged as prospectors in trying to find and explore traps similar to those already known or, more rarely, traps which should perform the same function. Ours is an empirical science.

Drilling of the Test Well

The problem of drilling the exploratory well differs from problems of ordinary development drilling only in the greater necessity for being able to test every oil- and gas-show in what is essentially untried ground and in the greater importance of securing all geological information which might be pertinent to a solution of the particular problem of exploration. Once a pool has been discovered, the objectives of subsequent wells—depths, casing programmes, producing sands, &c.—are fairly well known or can be estimated closely. The exploratory or wild-cat well, however, must be drilled more slowly, with greater care, and is generally more expensive than the development well. Every device or improvement which will aid in securing more exact or a greater amount of information is correspondingly important.

The nascent petroleum industry received its drilling equipment ready made. The standard, cable, rope, or churn-drill system, as the percussion system has been variously called, had been used for drilling brine-wells during the half-century preceding the drilling of the Drake well. It was used for drilling practically all the oil-wells in the United States during the first 40 years of the industry, and, to within the last 15 years, was regarded as the best, if not the only, system for drilling hard rocks and as the only satisfactory system for prospect or test drilling where it could be used.

The percussion systems, standard-cable, or variants such as Canadian pole tool, Galician, or Russian free fall are of very ancient origin. The Chinese were drilling brine-wells to depths of 1,500–1,800 ft. more than a century ago by methods which are essentially the same. Modern plants are of greater strength and size, of improved design, have various refinements to facilitate handling, and greater and better power application, but are fundamentally the same. Rock is drilled by the percussion of the falling bit. Cuttings are removed by the use of sand-pump or bailer, and the hole is cased as required. Generally the hole is kept dry except for a small amount of water put into it in order to facilitate drilling and the removal of cuttings, though it may also be drilled loaded with mud or water. Manifestly, a well drilled by such system is constantly in an almost ideal condition for testing. Any oil- or gas-show encountered is likely to demonstrate its calibre at once. The source of cuttings can be determined easily to within a few feet. The disadvantages are relative slowness of drilling, necessity for using large amounts of casing either to shut off water-sands or prevent caving, and, with such use of numerous strings of casing, limitation as to depth.

In the soft and unconsolidated rocks of the Gulf Coast of Texas and Louisiana, where cable tools were not successful because of the constant caving and flowing of the formations, a new system was introduced: the rotary, hydraulic, or water-flush system. This system, whether invented by the Baker brothers from South Dakota or developed from some older type of diamond drill, is based, as are all other water-flush systems, on a method invented by Beart, an Englishman, designed by a French engineer, and known, after him, as the Fauville system. It was first used in 1846 in the drilling of a well at Perpignan, France. In this system the rocks are cut by a bit on the end of a turning, hollow, drill stem through which water or mud is forced. The water or mud carries the cuttings outside the drill stem up to the surface.

The advantages of the rotary system are speed in drilling and economy of casing and consequent ability to drill to increasingly greater depths. The disadvantages, in its earlier state, were difficulty in drilling hard rock, difficulty in recognizing and testing oil-, gas-, or water-bearing formations, and difficulty in securing exact geologic information. These defects have been remedied, and the modern rotary system has largely displaced all other systems as a prospecting tool except in regions of hard rock and for very rare and very especial cases. As early as 1925, an engineer with world-wide experience in drilling and acquainted with all drilling systems in actual use, summarizes a discussion of drilling methods with: 'The modern rotary is, however, revolutionizing drilling practice, and except in hard compact sandstones or limestones, it is replacing all percussion systems.' (Thompson, A. Beeby, *Oil-field Exploration and Development*, &c., p. 617 (London, 1925).)

The technical history of recent improvement in prospect drilling is essentially a history of the development of the rotary system.

The greatest and possibly most important improvement in drilling technique from the viewpoint of the prospector has been the constantly improving ability to achieve increasingly greater depths. We are finding important oil-pools to-day at depths of 7,000–10,000 ft. which could not have been reached by the drill under the best practice of 10 years ago. Oklahoma City and Kettleman Hills have already been cited as examples of pools, previously drilled, which remained undiscovered until we had achieved ability to drill to necessary depths. A consideration of the accompanying chart of well-depth and some acquaintanceship with the technique of drilling suggests that increasing depth has come about as a result of better material, equipment, and greater power rather than from any fundamental change in design. In the opinion of the writer, the standardization of drilling equipment programme of the American Petroleum Institute has been one of the greatest single factors in contributing to this condition.

The rotary system of drilling, which is the actual, if not the intentional, descendant of some early form of diamond

drill, was first used by the oil industry at Corsicanna, Texas, in the 1890's. The system had previously been used for drilling water-wells, a well having been drilled to a depth of 3,070 ft. at Galveston. The great impetus to its widespread use, however, came with experience gained in the development of the fields of coastal Texas and Louisiana, following the completion of the Lucas gusher at Spindletop, Texas, in January 1901. It was used exclusively in the exploration and development of the fields of coastal Texas and Louisiana.

As early as 1906 the rotary was used to penetrate the soft sands and shales near the surface in the Santa Maria field of California, and it was used in late 1910 to drill 10 wells to depths of 1,700 to 2,000 ft. for one company in that State. The design of drilling machinery was greatly strengthened and improved to meet the more severe requirements of California conditions, and by 1914 the California equipment was regarded as the best obtainable. About 1910–12 the rotary was being widely used in Mexico, and somewhat later it was introduced into the Roumanian and Russian fields. It was first widely used in Oklahoma in the development of the Tonkawa field in the early 1920's.

In all fields, particularly before the perfection of the rock bit, it was necessary to change over to the standard system when hard rock was encountered in a well being drilled by rotary, and, as late as 1916, it was the custom in California to finish all rotary-drilled wells with standard tools, a custom which was followed in Mexico and which was regarded as best practice in Oklahoma until quite recently. Indeed, this practice was so common that the Californians designed a combination rig which could be changed easily from one system to the other, and this type of rig from about 1912 to 1918 was regarded as the finest type of drilling equipment.

In the earliest rotary practice the circulating medium was water, and its function was apparently regarded as simply that of removing cuttings. Attempts were made to follow down the hole with casing as drilling progressed, much in the fashion of standard-cable practice. It was soon obvious, however, and was noted by Ben Andrews, sen., of New Orleans, that the use of heavier mud for circulation served to wall up the hole and reduced the casing problem to a minimum.

The problem of drilling hard rock was solved by the invention of the rock bit in 1908 and its subsequent perfection and adoption by the industry. Further advances in this direction were made through the adoption some 10 years later of various hard-surfacing alloys, the first of which was stellite, for facing the cutting-edge of ordinary bits such as the fish-tail type.

Up to this point in the development of the rotary system, which was about 1920, the rotary as a tool for making holes had been fairly well perfected, but there had been no notable correction of its deficiencies as a tool for testing. It was no unusual thing for important oil-bearing formations to be passed through without recognition, and it was seldom indeed that water-bearing sands were noted. As late as 1922, the writer protests vigorously against the selection of the rotary by clients for drilling a wild-cat well.

The first real forward step in the improvement of the rotary as a testing tool came with the introduction of the improved core barrel and improved coring practice about 1921. Some coring had been a part of good rotary practice since a very early date, but the core tool was a rather crude affair, the old basket type of barrel consisting generally of a section of casing in the lower end of which teeth or notches had been cut, and core recovery was neither exact nor satisfactory. The earliest of the new double-core barrels with a special cutting head was introduced in California in late 1921 by J. E. Elliot, who had redesigned a tool built by Jan Koster for the Geological Survey of Holland and which had been introduced into the United States by the Survey's late director, Dr. Van der Gracht, then head of the Roxana Petroleum Corporation, for use in core-drilling for geologic structure. With several improvements in design and constant improvement in practice, recovery of cores had been perfected to such an extent that the use of the core barrel is now common rotary practice, and cores secured yield the highest type of geological and practical data which can be secured from a prospect well. The Robischeaux core barrel which, while it secures a smaller core, can be run and withdrawn after taking core without the necessity for pulling the drill stem, supplements the more elaborate type of coring to a degree which allows a geological log of the drilling well to be made which is in no way inferior, and in some ways superior, to those which can be made for holes drilled by any other system.

One of the most notable improvements in the rotary system as a testing device was the introduction of drill-stem testing. The drill stem, closed by a valve at the lower end, is seated with a packer, generally on a shoulder left just above the formation to be tested. The valve is opened and closed by manipulation of the drill stem, and, upon withdrawal, one may judge from the amount and nature of the fluid which the drill stem contains, and the amount of time it has been open, something of the probable value of the formation tested. One of the earliest forms of drill-stem testing consisted of a stem closed with a plate of glass at the lower end instead of a valve. It was used in southwest Texas as early as 1926. The glass was broken by dropping a go-devil, and there was no method of closing it, the drill stem remaining open and seated long enough to allow the fluid from the formation being tested to reach the surface. Drill-stem testing is a common and widely accepted element of rotary practice at the present time.

Of as great or greater importance in improving the testing abilities of the rotary was the introduction of electrical coring. This method, developed as early as 1928 by C. and M. Schlumberger of Paris, consists essentially in measuring the resistivity and electro-filtration of the walls of a drill-hole by the introduction of a series of electrodes. The resistivity log gives information as to oil, gas, and water content. The electro-filtration is studied by the measurement of potential differences and is regarded as an index to porosity. The advantages of electrical coring, which has been widely adopted within the past few years, are to reduce to a minimum the hazard of failing to recognize important oil-, gas-, or water-bearing formations passed through and of furnishing a log which, for correlation purposes, is often superior to any other type of log and which, in specific cases, may even be of greater utility than a complete core section.

A further improvement in rotary-testing practice has come about within the past few years through the introduction of the shot-gun perforator. This is a device which is used for perforating the casing and some inches of the bounding formation, at desired points, by the firing of small steel projectiles. This advance in technique permits a formation to be tested after it has been cased off. In actual practice entire formations, including a number of oil-

and gas-shows, may be penetrated, a single string of casing set and cemented throughout the important section of the hole, and tests may be made at each and every point desired.

Various additional improvements of less importance have been made which have bearing on the perfection of the rotary as a testing tool. Hole surveying serves both to furnish more precise information as to the exact course followed by the drill and as a basis for keeping it straight, if so desired, or as a guide and check for directional drilling. Directional drilling, itself, has been improved within the past few years to a point which greatly increases the possible testing value of a single hole. The improvement of drilling muds serves both to keep the walls of the hole in proper condition and to prevent blow-outs, and so admits of economy in the use of casing, the attainment of greater depth, and prevents the loss of holes. In actual testing, the widespread use of 'chokes' or 'beans', both in drill-stem testing or in actual completion and flowing through tubing and at both the top and bottom of the well, provides a less violent and sounder method of testing oil- and gas-shows of certain types than is afforded by any other method, even the open hole of the standard-cable system.

Many of the improvements in rotary testing should be usable with the diamond drill, which has also been used by the industry, but on theoretical grounds there is no particular difference between the two systems, and modern rotary design already has taken advantage of such improvements as may, at one time, have been peculiar to the diamond drill.

A prospect well, with rare exceptions, in the writer's opinion, can be drilled more quickly, more cheaply, and to greater depth with the rotary than by any other method. Surveyed, cored at important points, logged electrically, drill-stem tested where desired, cased and cemented, and finally perforated for testing by stages, the rotary-drilled prospect hole should be as thoroughly tested as is possible by current methods and equipment for any system.

TABLE I

Chronological List of Deep Wells

Year	*Well*	*Ft.*
1897	Bedell well, Pennsylvania . . . . . . For many years, probably until Geary well, was deepest well in the United States and probably the deepest well drilled for oil in the world.	5,582
1909	Czucho well, near Breslau, Silesia . . . . Coal prospect hole, and deepest well in the world.	7,348
1917	Geary well No. 770, Pennsylvania . . . . Cable tools, deepest well in United States and second only to Czucho well.	7,248
1918	Goff well, West Virginia . . . . . . Cable tools, world's deepest well.	7,386
1919	Lake well, West Virginia. . . . . . Cable tools, world's deepest well.	7,579
1925	Ligonier well, Pennsylvania . . . . . Cable tools, world's deepest well.	7,756
1927	Olinda well No. 96, California . . . . Rotary tools, world's deepest well.	8,201
1928	University 1-B, Big Lake, Texas . . . World's deepest well.	8,523
1929	Nesa well No. 11, Long Beach, California . . Rotary tools, world's deepest well.	9,280
	Hathaway well No. 7, Santa Fe Springs, California . Rotary tools, world's deepest well.	9,356
1930	Mascot well No. 1, Midway, California . . . Rotary tools, world's deepest well.	9,629
1931	Williams well No. 1, Semi Tropic, California . . Rotary tools, world's deepest well.	9,702
	Hobson well No. 2-A, California . . . Rotary tools, world's deepest well.	10,030
	Jardin well No. 35, Alamo, Mexico . . . Cable and rotary tools, world's deepest well.	10,528
1933	Lillis-Welch well No. 1, Kettleman, California . Rotary tools, world's deepest well.	10,924
1934	Berry well No. 1, Belridge, California . . . Rotary tools, world's deepest well.	11,377
1935	McElroy well No. 103, Upton Co., Texas . . Rotary tools, world's deepest well.	12,786

MAPS

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Chief Geologist, Sun Oil Company

In the oil industry a great many different kinds of maps are used. Some are prepared to facilitate the marketing of refined products. Others show the distribution of pipelines and the various channels for transportation of crude oil. And still others are made to indicate where oil may possibly be discovered underground by drilling, or where oil has already been found and is being brought to the surface for exploitation. In the following pages this discussion will be confined solely to maps of the last kind—maps used in the search for oil and in its production.

Maps may be described both as to the methods by which they are constructed and as to their uses and interpretation. Every map should be provided with a scale, an arrow, or other means of indicating compass directions, and a legend to explain the meaning of symbols, colours, or other special signs and patterns employed on it.

Surface maps are those which portray features of the earth's surface. They include aeroplane photographs, outcrop maps, areal geological maps, topographical maps, well-location maps, structure contour maps, &c. Subsurface maps show underground geological conditions which may be interpreted from well data or from geophysical data.

Surface Maps

The most detailed and accurate maps of the ground surface, if properly made, are photographic views taken from an aeroplane. A high degree of precision has been attained in preparing these photographs, mounting them, and reproducing them to true scale. In some regions where geological structure is revealed by differences in soil and vegetation, or in continuous ledges or larger topographic forms, these aerial maps cannot be surpassed. They are excellent as base maps on which to plot the distribution of rock outcrops, and as base maps for locating stations for geophysical work. Figs. 1 and 2 illustrate two of these maps.

Topographical maps show the surface forms of the earth, such as hills, valleys, &c., usually by contours, a contour being a line having everywhere the same elevation above mean sea-level. On any given map these contours are drawn to represent elevations at regular intervals, as, for instance, every 10 ft. above sea-level, or every 20 ft. above sea-level, and so on (see Fig. 3). Maps of this kind are also of value as base maps on which to plot geological information.

Where less detail is necessary for such base maps only a few features may be accurately surveyed and plotted, such as roads, streams, and property lines when needed; and on such a skeleton map geological data may be sketched.

Outcrop maps indicate the positions of actual exposures of rock, and, if the formations are inclined strata, these maps should show the dip and strike of the bedding at each of the outcrops (see Fig. 4). From a careful study of outcrops, and of soils between these outcrops, it is generally possible to trace the contacts between formations. These contact lines can then be charted and the formations between them can be coloured or otherwise distinguished on the map, thus producing an areal geological map (Fig. 5). On these maps thin soils are usually disregarded, so that the picture is essentially one of the underlying rock formations as these would appear if the soil were removed.

In regions where the rocks beneath the soil consist of low-dipping strata, the geologist may make a structure contour map (Fig. 6). To do this he chooses an easily recognizable bed on which, at various points, he determines the elevation. This is his 'key bed'. Elevations on it may be referred to sea-level by using bench marks already established by precise levelling, or they may be referred to some other assumed datum plane. These elevations are surveyed by plane table, transit, hand-level, or barometer, depending upon the nature of the country, the degree of accuracy required, the time and money available for the work, and a number of other factors. If the selected key bed dips underground, another higher bed is mapped and the interval (thickness of strata) between it and the lower key bed is subtracted to reduce all elevations to this lower horizon (see Fig. 6). Similarly, if the dip of the formations carries the key bed up above the present land surface, where this bed has been eroded away, a lower recognizable bed is mapped and the interval between it and the key bed is added to give elevations on the latter (see Fig. 6).

Subsurface Maps

Subsurface maps are constructed from underground data. For example, where an area is so covered with soil that outcrops of the bedrock are few or absent, holes may be drilled at selected points to determine the attitude of some key bed which may lie a few hundred feet deep (Fig. 7). In unexplored country search has to be made for such a key bed. Sometimes no bed is discovered, within drillable depths, sufficiently distinctive to be recognized in scattered core-holes. Generally, by the study of a considerable section penetrated in the drilling a key horizon can be found. The depth to this key is carefully measured at each hole and is subtracted from the ground elevation of the hole, in order to adjust all elevations to the same horizontal datum (sea-level or assumed). Contours are then drawn in reference to these scattered points—one point at each hole.

In the case of deep drilling the process is similar. Some recognizable key horizon is chosen and its sub-sea depth is calculated in each well, after which the structure on this key is represented by contours.

Obviously contour maps of the kind just described, even if absolutely correct as to elevations on the key bed in the drilled holes, are subject to increasing error in their construction in proportion to increased distance between the holes. Subsurface contour maps based on widely scattered data are merely suggestive, and should be viewed as such. As more holes are drilled, the new information may require extensive modification of earlier interpretation (Fig. 8). Because of this fact, that some degree of inaccuracy is unavoidable in constructing these maps, they have sometimes been ridiculed by people who do not fully understand how they are made. On the contrary, others have placed too much reliance on them and have used them as infallible

FIG. 1. Aeroplane map of parts of township 2 south, range 14 east, Atoka County, Oklahoma. The ridges are due to differences in the resistance of the rock formation to erosion, the harder layers standing out as ridges. Published by permission of Edgar Tobin Aerial Surveys.

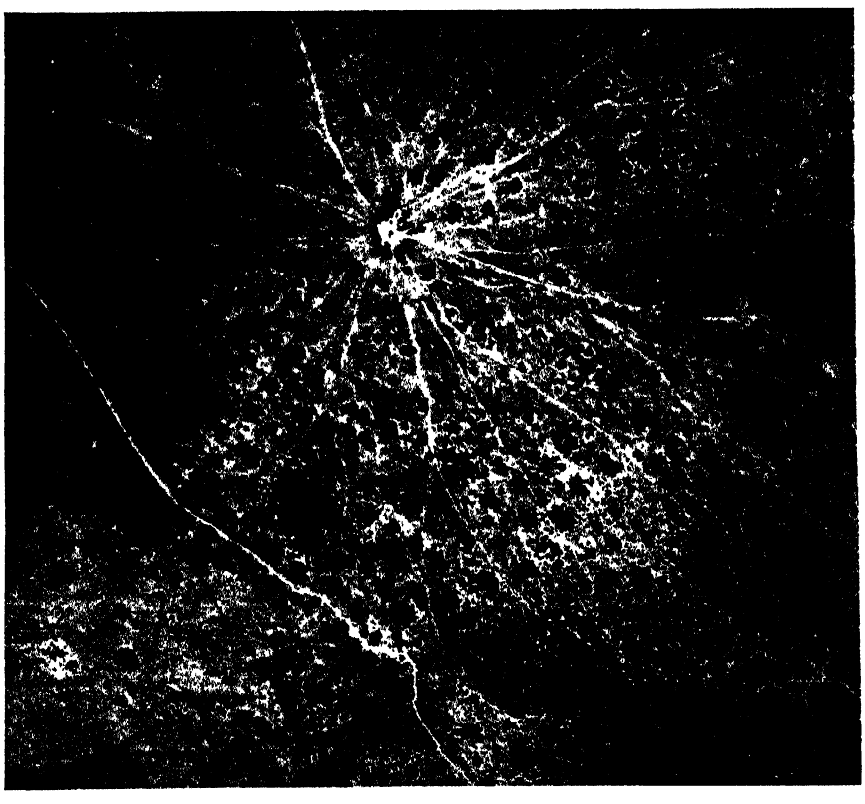

FIG. 2. Aeroplane map of part of Brooks County, south Texas, where there are large ranches, few roads, and practically no rock outcrops. Cattle trails are seen radiating from a water well, the dark patches being low brush. Published through the courtesy of Edgar Tobin Aerial Surveys of San Antonio, Texas

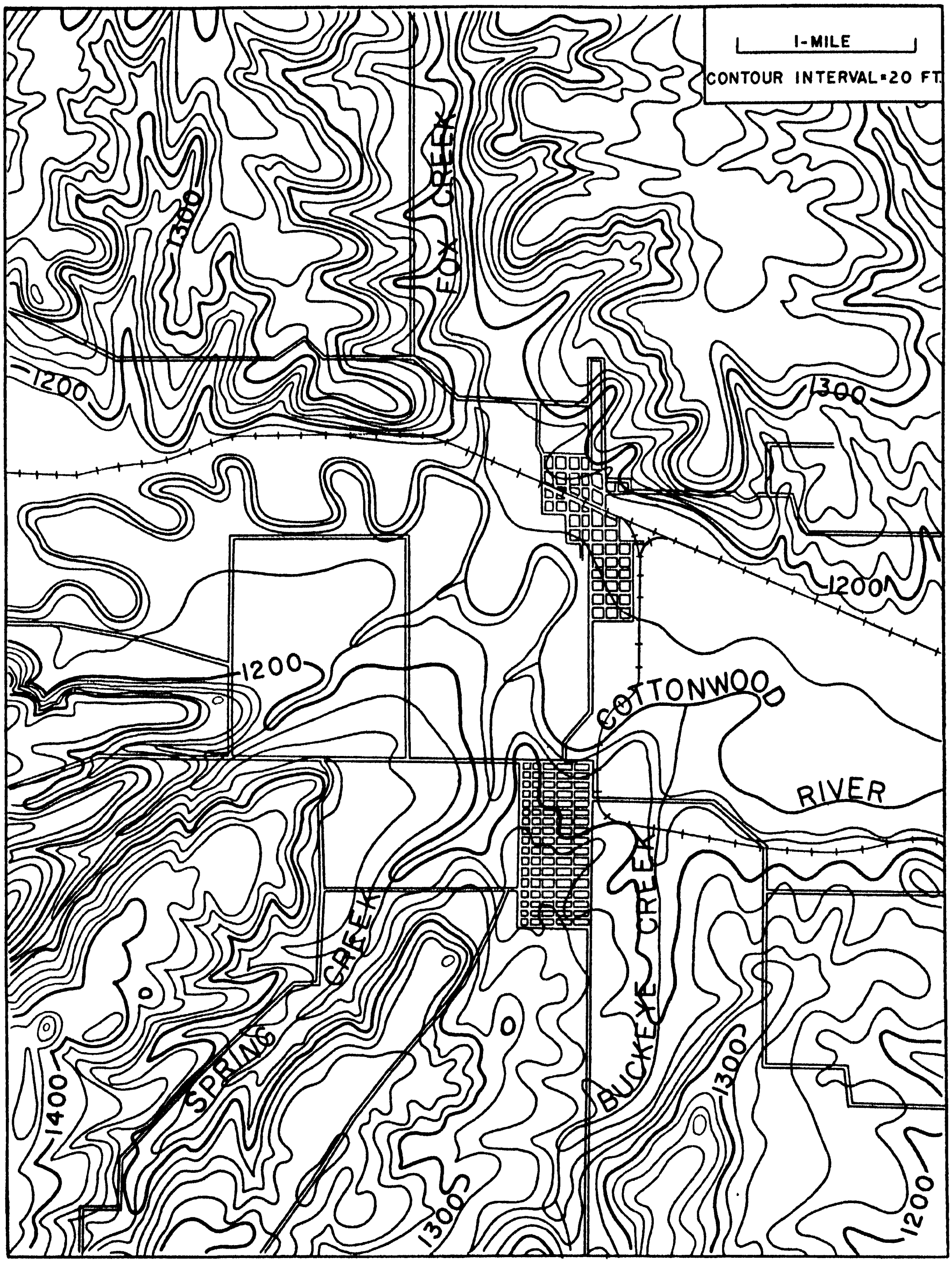

FIG. 3. Part of the U.S.G.S. Cottonwood Falls Quadrangle, Kansas, with some names and other features omitted. This is a topographical contour map, with a 20-ft. contour interval, showing elevations of below 1,180 ft. to more than 1,460 ft. above sea-level. Obviously slopes are *down* towards the streams. Roads and streets are shown by double parallel lines.

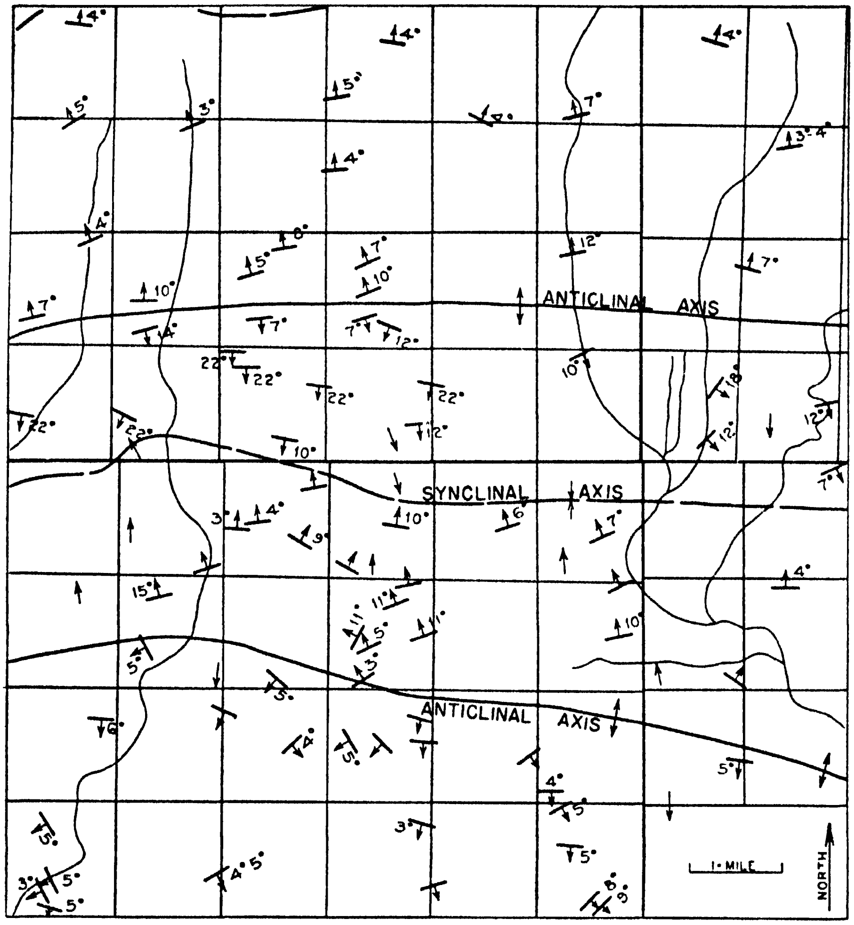

FIG. 4. Outcrop map, showing an area in Arkansas. Details omitted. Arrows point down dip. Cross-lines on arrows indicate direction of strike. Amount of dip of bedding, as measured at each outcrop, shown in degrees. The squares are sections (1 mile on each side).

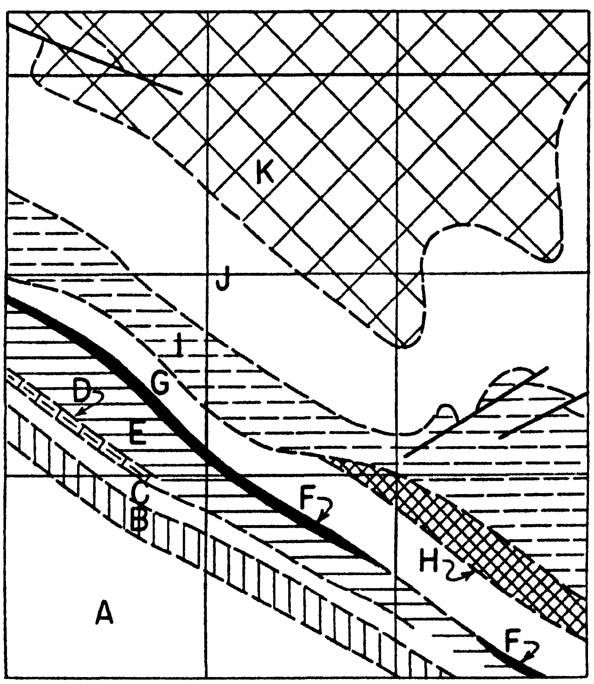

FIG. 5. An aerial geological map, the several formations (*A* to *K*) being indicated by various patterns. The contacts between these formations were first mapped as explained in the text.

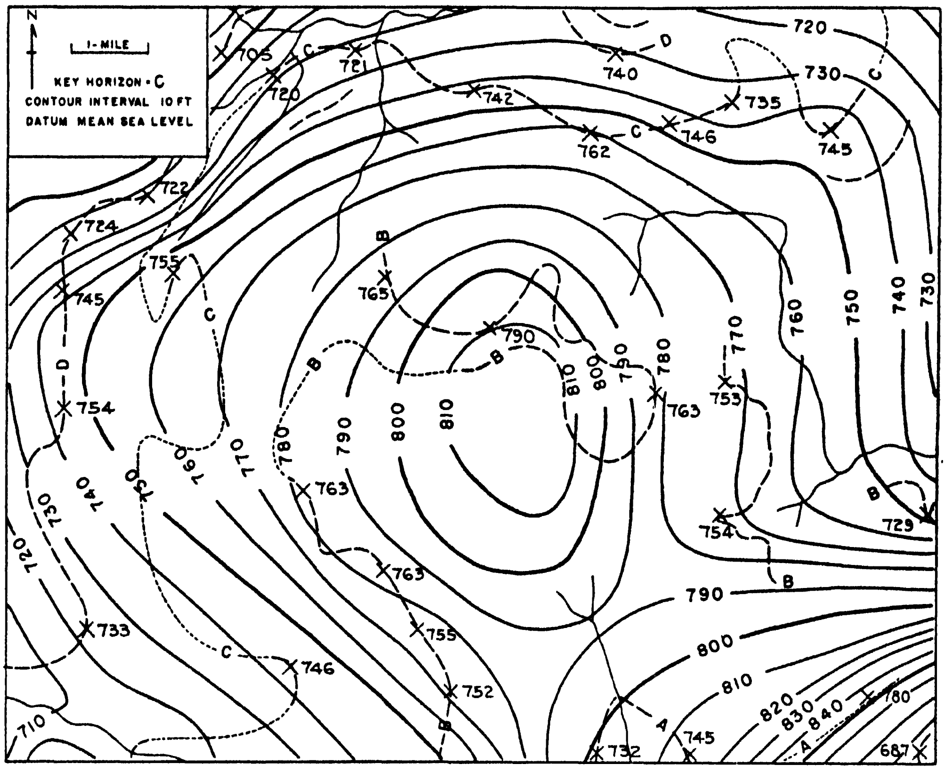

FIG. 6. Structure contour map of a key horizon (C) which has been traced and mapped on the ground and on which the elevation of several points above sea-level has been charted. *A*, *B*, and *D* are other beds, *A* and *B* being respectively 70 ft. and 20 ft. stratigraphically lower than *C*; and *D* being stratigraphically 10 ft. higher than *C*. Consequently, in making this map, where all contours are reduced to *C*, 70 ft. had to be added to all elevations recorded on *A*; 20 ft. had to be added to readings on *B*; and 10 ft. had to be subtracted from elevations recorded on *D*.

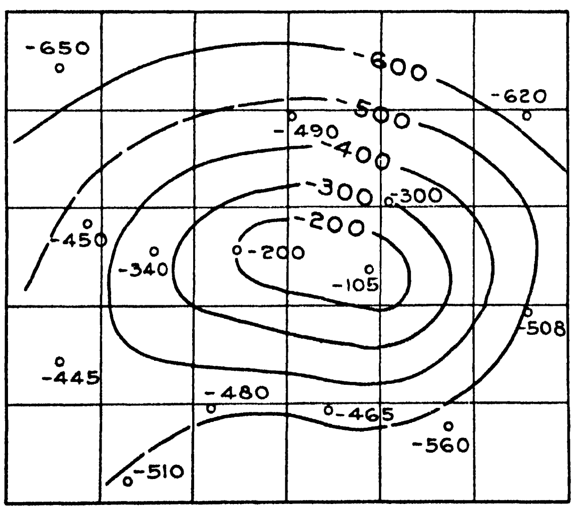

FIG. 7. Structure contour map of a dome which was found by drilling several hundred feet below the soil-covered surface of the ground. The contours are drawn on a fossiliferous key horizon discovered in the drilling. Elevations are below sea-level. The squares are a mile on each side.

pictures of the real underground geological structure. It is important that these maps be given their proper weight. They are valuable as guides to an understanding of subsurface conditions, but they are not precise representations.

The foregoing remarks refer to data obtained from holes drilled vertically. If for any reason the holes deviate from the vertical, an error is introduced into the actual elevation recorded on the key horizon. This is a much more serious defect than the inaccuracies caused merely by generalizing between the points of measurement. Every effort should be made to secure correct basic data. To this end holes are surveyed at intervals during their drilling, and if they are found to be running off plumb, they are brought back into line, or they may be redrilled. If in spite of every precaution they cannot be kept vertical, or if they are intentionally whip-stocked into an inclined position, they must be surveyed for the true location of the point where the key bed was penetrated before the recorded depths to this key can be used in the construction of a contour map. In such cases of deviation from plumb, the point on the key may be considerably displaced both vertically (depth) and horizontally (mapped position of hole). This should be borne in mind not only for subsurface contouring, but also for any map which is intended to give correct relations of land lines and well locations on the ground to the points where these wells reach the oil or gas pay bed. Certainly a map showing regularly spaced wells on a lease is of no value as a guide for development if the wells do not bear the same horizontal spatial relations on the producing formation (Fig. 9).

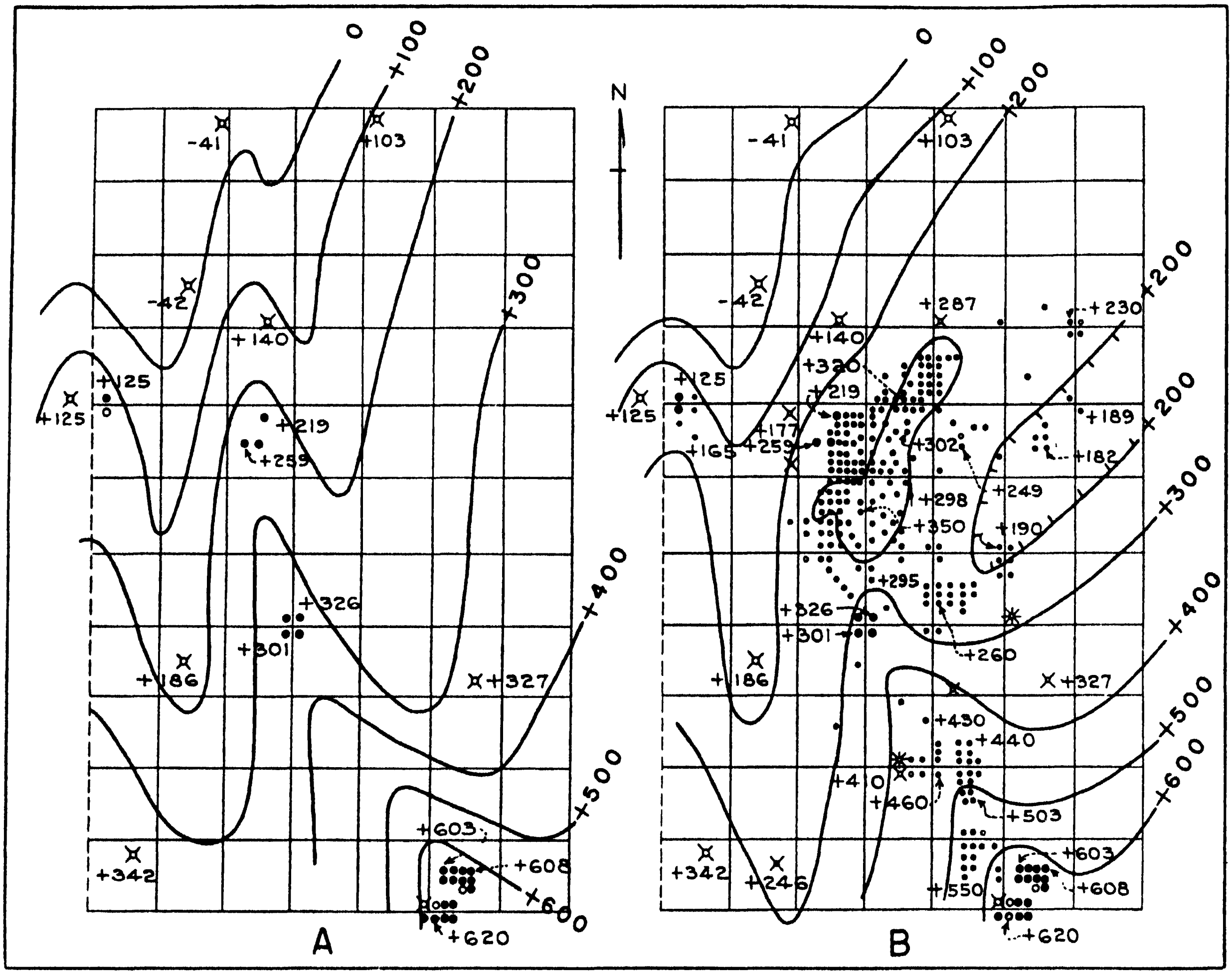

FIG. 8. Subsurface structure contour maps of the same area (*A*) when data were available from only a few deep holes, and (*B*) after many more wells had been drilled and had furnished additional information. Note that the main feature, the anticlinal nosing in *A*, still persists in *B*, though a closure has been proved to exist on it. The low dip in the north-west quarter of *A* by later drilling is shown to consist of a low structural ridge and a structural depression (*B*). The squares are 1 mile on a side.

Isopach maps are used to show, by lines of equal thickness, the variations in vertical interval between any two geological horizons. Since these maps represent thinning of this interval in certain directions, they are also called 'convergence maps' (see Figs. 10, 11). Such maps are of particular value in projecting reasonably certain structure on one key bed downwards to a lower stratum between which and the upper horizon the interval is known at relatively few points.

Maps somewhat similar to contour maps are constructed to show the variations in total solid content, or in total chloride content, of underground waters over considerable areas; or to show variations in recorded pressures in producing oil-pools. Fig. 12 is an example of an isochloride map where the lines are drawn between scattered wells from which water samples were secured and analysed for their chloride content. All the samples came from the same sand body (Woodbine sand).

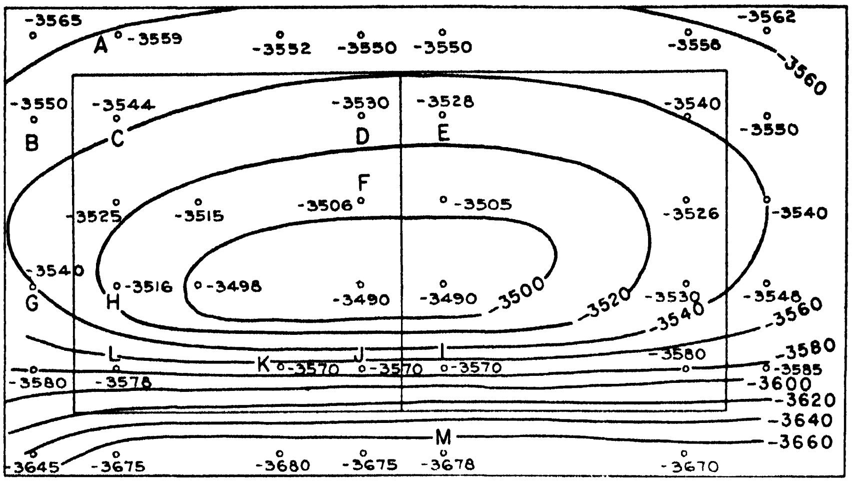

FIG. 9 *A*.

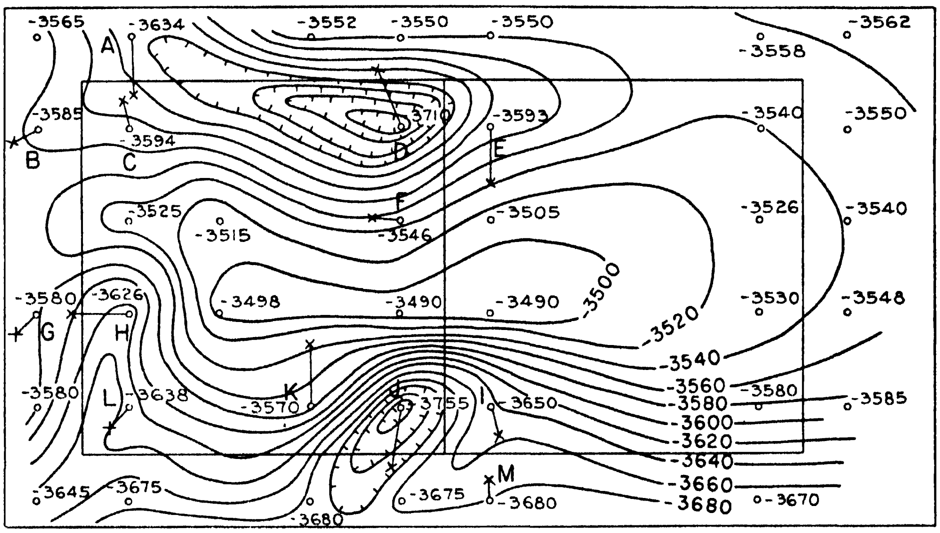

FIG. 9 *B*.

FIG. 9. In Fig. 9 *A* is shown an elongate dome with elevations on the pay sand ranging from 3,490 to 3,680 ft. *below sea-level.* Here all holes are assumed to be vertical. Depth to the pay is assumed to be 5,000 ft., more or less.

In *B* the lettered wells are assumed to be inclined at a uniform angle from the surface to the bottom of the hole, as listed below. The cross marks the actual point vertically below ground where the hole reaches the pay sand, and the recorded elevation was obtained from the measured depth of the inclined hole. We are assuming that the inclined holes are *thought* to be vertical, so that the incorrect depths are recorded as if they were correct below the position of the mouth of the hole.

From incorrect data of this kind, map *B* is constructed, giving an entirely erroneous idea of structure. Furthermore, note the spatial relations of the crooked wells (crosses) as contrasted with their intended positions (circles). Holes *A*, *D*, *H*, and *J* have actually crossed the property boundary on to adjoining land.

The squares are 1 mile on a side.

The following are the data for the inclined holes:

	Inclination from vertical	*Direction of deviation*	*Approx. dip*
A . .	10°	Up dip	100 ft. per mile
B .	5°	Along strike	. .
C . .	5°	Down dip	100 ft. per mile
D .	10°	,,	,, ,,
E . .	10°	Up dip	,, ,,
F .	5°	Along strike	. .
G . .	5°	Down dip	100 ft. per mile
H .	10°	,,	,, ,,
I . .	5°	,,	500 ft. ,,
J . .	10°	,,	,, ,,
K . .	10°	Up dip	,, ,,
L . .	5°	Oblique	,, ,,
M . .	5°	Up dip	,, ,,

Fig. 13 shows the distribution of pressures measured at the bottoms of a selected, well-distributed number of wells in the East Texas field. The chart on the left indicates the bottom-hole or reservoir pressures in early 1933, and that on the right the bottom-hole pressures in the spring of 1935. In the 26 months between the two groups of observations there was an average drop in reservoir pressure, as measured at the bottoms of the holes, amounting to an average of 190 lb. per sq. in., while during the same period over 441,000,000 bbl. of oil were produced. Maps of this kind are used to show progressive change in pressure in pools which are in process of drilling and producing, for these data are of value in assisting engineers to formulate and maintain a programme of rational development.

Geophysical Maps

The following description of geophysical maps was kindly prepared by H. W. Rose at the author's request.

Geophysical maps are maps which represent measurements of some physical quantity or quantities, the variations of which from place to place are directly or indirectly connected with the composition, mode of origin, and/or the structural attitude of the rocks of the subsurface. Most geophysical measurements are made with instruments set at selected points on or near the earth's surface, but valuable information can be and often is obtained by placing certain types of instruments below the surface in deep wells or in mine workings.

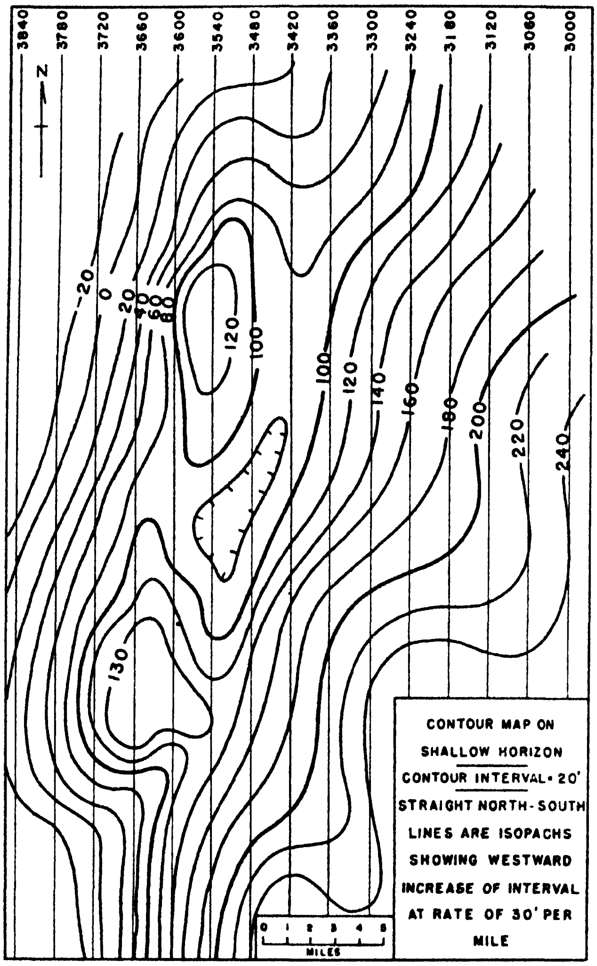

Fig. 10.

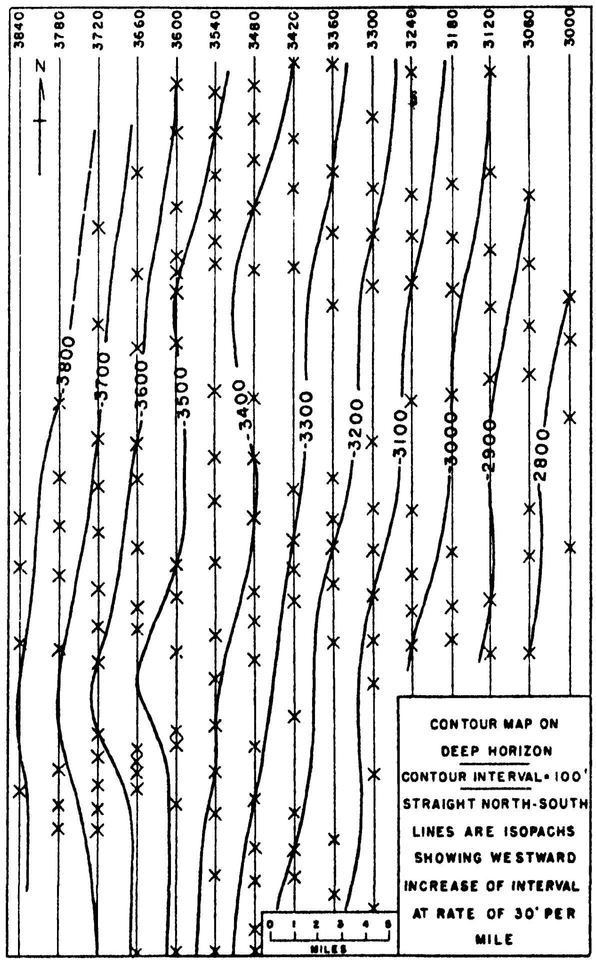

Fig. 11.

Fig. 10. Map of shallow subsurface structure as determined by core-drilling. The zero contour is at sea-level. On this map is superposed a 'convergence map', here assumed as very regular, the convergence being at the rate of about 37 ft. per mile due east; i.e. westward *increase* in interval of 37 ft. per mile between the shallow horizon, here contoured, and a deep horizon some 3,000 ft. below. The isopachs, or lines of equal interval, are shown as straight north-and-south lines. Under natural conditions thinning and thickening would not be regular, and isopachs would therefore bend more like ordinary contours.

Fig. 11. Same area as shown in Fig. 10. The convergence map (isopachs) of Fig. 10 has been repeated here. On the isopachs are crosses which mark the points where contours of Fig. 10 cross isopachs of Fig. 10, and where the interval between the shallow horizon and the deep horizon was calculated by subtracting the shallow contour value from the isopach value. For instance, where the plus 200-ft. contour crosses the 3,000-ft. isopach the deep horizon is 2,800 ft. below sea-level. With these calculations made at each such point, contours were drawn on the deep horizon, producing the structure shown in Fig. 11. Observe that the westward increase in interval between the shallow and deep horizons has completely eliminated the two anticlinal closures and the associated shallow basin (Fig. 10) in the deep horizon. Only a slight flattening of the dip appears here in this deep horizon.

This illustrates what *may* happen to small surface structures with increasing depth. It also demonstrates what important structural effects may result with increasing depth as a result of convergence between formations.

The value of geophysical maps is derived chiefly from the fact that an experienced interpreter can use them to draw certain conclusions about local or regional geological conditions in the area covered. Skilfully used, therefore, geophysical information as represented on geophysical maps becomes an almost indispensable tool of the modern geologist in the exploration of petroleum and other minerals. This is especially true in areas where the surface geology affords little or no clue to possible geological structures at depth, or where scanty subsurface information must be supplemented by information derived from sources more economical than the haphazard drilling of very expensive deep test wells

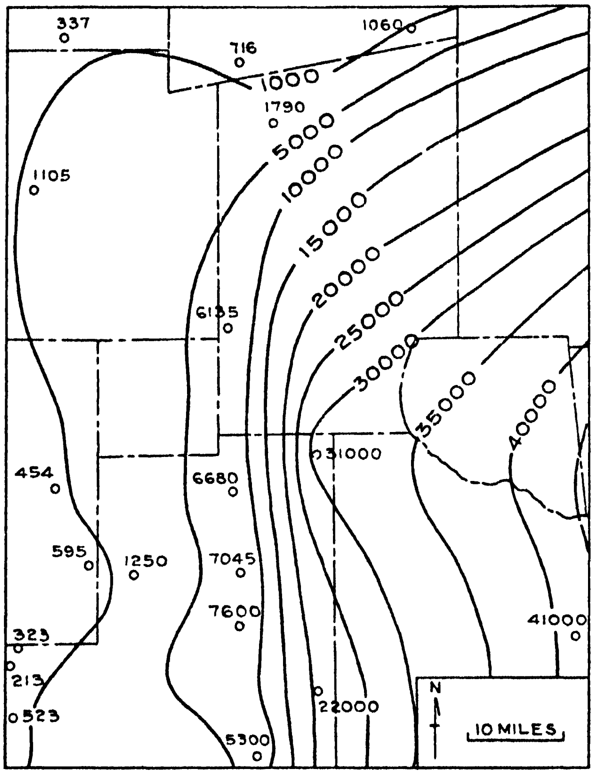

Fig. 12.

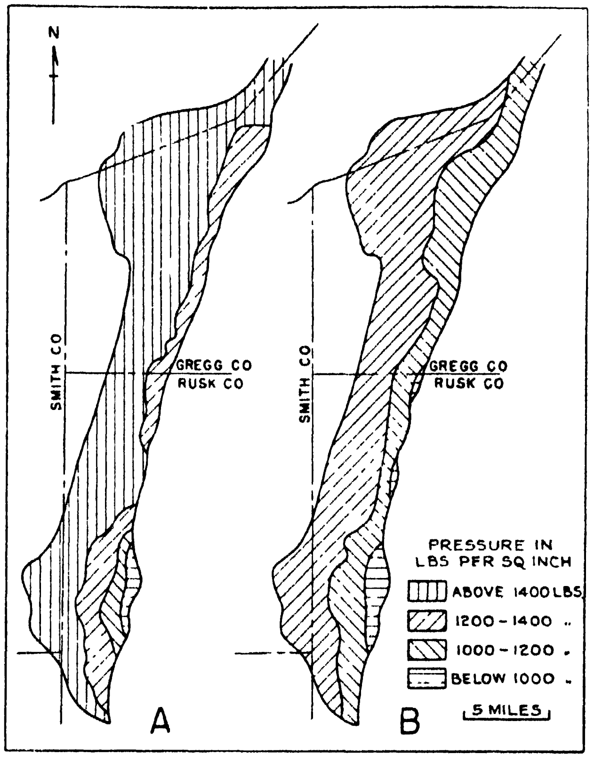

Fig. 13.

Fig. 12. An isochloride map showing, by lines of equal chloride content (isochlorides), the eastward increase in the amount of chlorides in water from the Woodbine sand in several counties in East Texas. The Woodbine formation outcrops not many miles north and west of the area mapped, and it dips eastward and south-eastward, reaching a depth of nearly 5,000 ft. in the south-eastern corner of the mapped area.

Fig. 13. Two maps showing average distribution of reservoir pressures in the East Texas field in early 1933 (*A*) and in the spring of 1935 (*B*). The pressures are highest on the west, or lower edge of the field, where the oil is backed, down dip (on the west), by water. They are lowest on the east where the pay sand wedges out up dip (eastward) beneath unconformably overlying strata. The lowering of pressure in the field as a whole has been caused by the production of some 441 million barrels of oil between the dates of maps *A* and *B*.

The accuracy of geological conclusions drawn from geophysical maps may have a wide range, depending upon surface and geological conditions and on the choice of the geophysical method. In some areas geophysical maps may give only the faintest of indirect clues to structure, but in other areas the proper choice of a geophysical method may yield information which indicates the almost certain presence of structure.

Three different geophysical methods have been used rather extensively in connexion with geological exploration for petroleum. They are (1) the gravimetric method, (2) the magnetic method, and (3) the seismic methods, which are dealt with fully elsewhere in this section.

AERIAL RECONNAISSANCE

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RECONNAISSANCE from aircraft for the location and development of oilfields may broadly be divided into visual and photographic methods, whose relative advantages and limitations should both be clearly understood.

Visual Reconnaissance

Visual observation from the air, being far cheaper than systematic photography and subsequent detailed examination of the photographs, is mainly of value in providing negative information: it may be possible as a result of a few flights to exclude certain areas from further consideration, leaving the more likely areas for detailed photographic investigation later. At the same time it should be realized that systematic photography of small isolated blocks cannot efficiently be undertaken, and that it must be possible to indicate the boundaries of areas to be photographed to the photographic crew. The aim of a preliminary visual reconnaissance should therefore be the selection of interesting blocks, not less than about 100 square miles in extent, whose limits may clearly be defined. The advantage of doing so from the air, as opposed to selection on the ground, lies in the comprehensive yet detailed view obtainable in a short space of time from aircraft.

If the visual reconnaissance is carried out from a high altitude, then obviously a greater area of country can be seen at once and will remain longer under observation, so that the broader surface features are more readily apparent. At the same time, so far as the binocular sense of the observer is concerned, the ground will be so far away as to appear flat. In cases where the geological structure is related to topographic relief, there is accordingly an advantage in flying lower at an altitude of a thousand feet or so. Impressions of relief obtained from such low-altitude flights can be correlated with indications derived from shadows and drainage and carried through to a return flight at a higher altitude of, say, 10,000 ft., during which the broader extensions of such features may be observed. From high altitudes the landscape may also appear monochromatic, owing to reflection of mainly blue light from intervening layers of haze; yet here again an appreciation of colour, to be derived from flights at a lower altitude may be necessary to distinguish changes in soil or vegetational types correlated with changes in the geological structure. The best system is therefore to combine systematic observation from high altitudes with close-up 'samples' from low altitudes. Since no great ceiling is required in any case, light two-seater aircraft with a low cruising speed and low operating costs may be preferred, although the risk of forced landing in broken country from the low-altitude flights may favour a three-engined machine.

The amount of information which may usefully be derived from visual reconnaissance depends to a large extent on available maps on which to record observations. If detailed, fully contoured topographic maps are available, such as would serve for the geological interpretation of topographic land forms, then the only further information obtainable from the air would relate to surface indications which might well be observed and recorded on the available maps during the course of visual reconnaissance flights alone, without the necessity for photography at all. But such cases will obviously be rare in the type of undeveloped country usually associated with oil prospecting. At the other end of the scale, if no topographic maps are available, then it will usually be possible to do no more by visual reconnaissance than select promising areas for photography, as previously recommended. It is perhaps unnecessary to emphasize that an oil geologist charged with this work should acquire air experience, preferably by flights over country with whose surface geology he is acquainted, and which is reasonably well mapped. Otherwise he would be likely to acquire no more information than an ordinary air observer with no experience of geological prospecting, and might thereby infer that air reconnaissance is of no value—a verdict which is certainly not in accordance with the growing weight of informed experience.

Types of Air Photographs

Air photographs exposed for reconnaissance, or other purposes, are usually classified as 'verticals', for which the camera is pointed as nearly as possible vertically downwards; and 'obliques', for which the camera is intentionally tilted, usually to the extent necessary to include an image of the horizon. Oblique photographs, being more closely allied to the normal type of view obtainable on the ground, are the easier to read, and will include a larger area of ground in a single exposure. Against that, they do not show the ground features in as great detail, and for this reason are not as extensively used for this particular purpose as vertical photographs. Even a major fault, or other extensive geological feature, in the background of an oblique photograph may be hidden by trees or by a slight rise of ground towards the camera, although it could be seen even in heavily afforested country if it happened to run towards the camera, and might in any case appear on succeeding exposures. Such wide features as eroded domes show up very well on oblique photographs, usually by a water pattern, whereas they might be missed in the limited area of a single vertical photograph (failing the systematic compilation of vertical photographs into a mosaic), and would almost certainly be missed, without a complete topographic and geological survey, by even the most exhaustive examination on the ground. Nevertheless, for the present purpose, the balance of advantage lies with the vertical photograph, and much the same conclusion applies to photographs exposed obliquely in multi-lens cameras and subsequently 'rectified' to provide a composite vertical photograph covering a wide field. Such photographs may be cheap, and may serve the purpose of a preliminary reconnaissance better than purely visual observation (especially where the latter is hampered by absence of maps), yet, nevertheless, the oblique view towards the edges tends to obscure detail—particularly in enclosed or broken country—which detail may be vital to a proper interpretation of minor geological features.

Arrangement of Photography

Air photography for systematic geological examination will usually be carried out by a specialized operating company, but the geologist should nevertheless understand broadly how it is done. To facilitate covering the area economically without gaps or excessive overlaps, as well as to simplify indexing and reference, the aircraft flies straight and level parallel courses at such an interval as will ensure that the 'strips' of photographs exposed on each flight completely cover the ground. A side wind will cause the machine to 'drift' off the 'course-steered' (that is, the direction in which the fore-and-aft axis of the machine is pointed) along a different ground track or

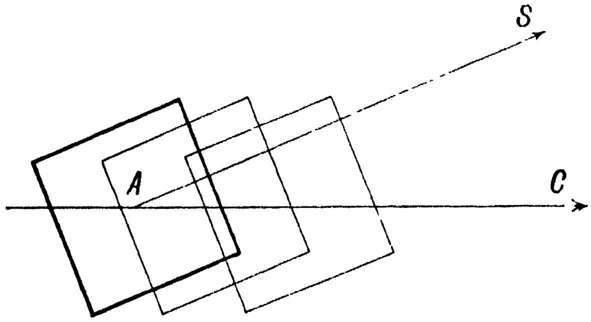

FIG. 1.

'course-made-good'. The angle between the two courses, or the 'angle of drift', must be determined by means of a suitable drift sight, after which the required steady compass course may be set to cover the general direction of the photographic strips. The actual photographs must be symmetrical about the course-made-good, so that provision is required for rotation of the camera in its mounting: if the camera remained fixed in its mounting with the sides of the photographs parallel to the fore-and-aft axis of the machine, then the effect of drift will be to stagger (or 'crab') successive exposures as shown in Fig. 1, where AS represents the course-steered and AC the track or course-made-good. This fault is likely to occasion gaps between strips and will reduce the area of the 'overlap' between successive exposures which is required for stereoscopic examination. Correct rotation of the camera for drift results in successive exposures appearing as in Fig. 2, in which the stereoscopic overlap is shaded.

The navigation of photographic strip flights is a skilled operation, on which depend economy and convenience in subsequent handling, if not the entire success of the operation. If no maps of a large area exist, it may be necessary to photograph strips around the boundaries of the area and to compile these into a rough map or mosaic, on which the starting and terminal points and tracks of the parallel strips may be plotted for use in the air. Such boundary strips may well be photographed with a multi-lens camera.

A common arrangement of oblique photographs consists of one photograph exposed forward along the track, followed quickly by successive exposures to left and right. Suppose, for example, that the camera is equipped with a lens of 7-in. focal length covering a 7-in. square photograph. A suitable altitude is 5,000 ft. With these data it may be calculated that the swing of the side obliques should be about 45°. The next set of three photographs would be exposed after an interval of about 2 miles, and a suitable interval between strips in order that the ground may be covered in reasonable detail would be 6 miles. Such photographs, although cheap, have the disadvantage that they cannot be examined in a simple stereoscope. They are, however, used to a large extent in Canada over flat country for the location of broad geological structures mainly associated with surface markings. If it is desired to examine oblique photographs stereoscopically, they should be exposed laterally by pointing the camera in a direction at right angles to the track.

Although a vertical photograph looks very much like a map or plan, it has, strictly speaking, no uniform scale, since the scale at a particular point will depend on the (small) tilt of the photograph and on variations in the relief of the ground. Nevertheless, it is convenient to speak of the rough scale of a vertical photograph, although it should be understood that this can only be exact in the case of an untilted photograph of flat country. Such a rough scale may be determined by dividing the focal length of the camera by the mean altitude of flight above the ground photographed. A 7-in. lens flown from 12,000 ft. will, for instance, yield contact prints on a scale of about 1/20,000 or nearly 3 in. to the mile. Vertical photographs for geological examination may conveniently be on a scale between 1/10,000 and 1/20,000.

To ensure that the whole ground is covered by stereoscopic overlaps, the interval between successive vertical photographs in a strip should be such as to allow a 'fore-and-aft overlap' of 50% of the fore-and-aft dimension of the photograph, and it is usual to allow 60% to avoid a break in stereoscopic overlaps through an accidental tilt, or sudden rise in altitude (of the ground or of the aircraft),

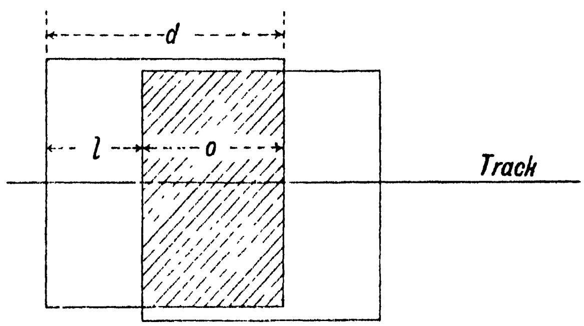

FIG. 2.

or increase in air speed. Thus in Fig. 2, o/d will usually be 60%. Successive exposures are made automatically on a time interval derived by calculation, or by observation in a suitable overlap sight. The 'lateral overlap' between strips is usually fixed at 25% to avoid a gap between strips occasioned by small lateral tilts or departures from a straight course. The amount of lateral overlap, in conjunction with the scale of the photographs, settles the distance between strips. Given the scale and the overlaps, it is also a simple matter to calculate the number of photographs required to cover a given area of ground.

Air photographs are usually examined or utilized in whole strips. There is accordingly some advantage in arranging the strips to run parallel to the broad topographic features of the country, if such there be. A better view of the steep slopes of mountain ranges, or a more continuous record of the structure of valleys, might, for instance, be obtained by doing so. A photographic pilot should not, however, be asked to fly accurate compass courses within, say, 10° of magnetic north. If he attempts to do so, a slight accidental banked turn out of a straight

and level course will cause the vertical component of the earth's magnetic field to act on his compass so as to indicate a turn in the opposite direction. Instead of correcting the initial turn, he is therefore likely to make it worse. This 'northerly turning error', as it is called, does not apply on southerly courses, on which the compass indications would be *more* stable. In the case of oblique photography, a further disadvantage of northerly (or in this case southerly) courses is that there may be a tendency for the midday sun to shine into the lens of the camera and fog the photograph.

Modern air cameras utilize roll film contained in magazines of 100 exposures, although it is usually possible to carry sufficient spare magazines for a photographic flight of any reasonable duration.

Stereoscopic Examination of Air Photographs

Any two successive vertical (or lateral oblique) photographs in a strip may be examined in a simple stereoscope to provide an impression of relief, provided that they have a sufficient overlap. The examination is very simply carried out if only such local impressions as a tree standing up out of its surroundings is required, or the detection of such structures as are associated with similar *sudden* changes of height or stereoscopic depth, but rather more care must be exercised if impressions of the relief of topographic features over large areas are required. Such wide impressions usually are required, at least in the early stages of geological examination. Methods will accordingly be discussed first for examining the entire overlap in correct stereoscopic relief: to relax the conditions for the less exacting conditions of local relief will then be a simple matter. It will be assumed that the photographs are vertical, although much the same conclusions would apply to lateral oblique photographs.

Air photographs used for surveying purposes have marks (known as 'collimating marks') along the edges or at the corners which may be joined to indicate a point near the centre of the photograph known as the 'principal point'. If no such marks occur on the particular photographs under examination, the geometrical centre of the photograph should first be marked as the intersection of small central portions of the diagonals, and taken to represent the principal point. The exact location of the principal point is not of very great importance, provided that it is marked consistently throughout a series of strip photographs. For this purpose it will be convenient to make up a celluloid template, which can be fitted over the collimating marks or corners of the photograph, and containing a central cross whose position can be pricked through to the photograph.

Ground detail around the principal point will also be photographed near the edge of the next photograph of the strip. Consequently the position of the principal point of each photograph of the stereoscopic pair can be transferred through such detail to the other photograph of the pair. If, for instance, the principal point falls on a bush, the same bush may be identified near the edge of the other photograph of the pair and suitably pricked or marked. The line joining a principal point to the transferred image of the next principal point is known as the 'principal point base line' and should be marked up right across the overlap on both photographs of the pair.

Place one photograph over the other so that the area of common ground in the overlap more or less coincides, and so that the shadows in the photographs run towards the observer; if necessary, turning both photographs round together to fulfil the latter condition. The photograph which is now mainly to the left will be called the left-hand photograph of the pair and will be examined with the left eye in the stereoscope. If the photographs are not placed thus correctly left to right, an inverted impression of relief might be obtained; hills appearing as depressions and valleys as spurs. But such an inverted impression would appear unnatural: the so-called common sense of the observer might outweigh his binocular sense and give him a weak impression, or illusion, of relief. Usually, if the photographs are inverted left to right, the result would be a drawn battle between common sense and binocular sense, and the landscape would appear quite flat. It is for much the same reason that the photographs should be so placed as to make the shadows run towards the observer, that is, away from the normal source of illumination *during examination*. In this way the impression of relief derived from shadows will *supplement* that derived from binocular sense, whereas if this recommendation is not followed the resulting unnatural run of shadows during examination might again result in a flat, or weak, stereoscopic impression.

Now lay a straight-edge on a wooden table roughly parallel to the edge of the table and consequently roughly parallel to the line joining the two eyes of the observer. Place the two photographs of the stereoscopic pair under the straight-edge in their correct relative positions, as obtained above, but separated so that the entire overlap can be seen on both photographs. Bring the two principal point base lines against the straight-edge and pin the photographs in this position to the table. Remove the straight-edge and examine the pair with a simple stereoscope, which for the present purpose may be of the ordinary hand prismatic type. A suitable cheap achromatic prism stereoscope for use with air photographs about 7 in. square can be obtained from such optical firms as Messrs. Adam Hilger. It is a mistake to attempt a saving of a few shillings by acquiring an inferior article made from non-achromatic combinations and possibly not even of optical glass. Neither can a stereoscope made of half-lenses be recommended for the present purpose of stereoscopic examination of the entire overlap, since the field of the cheap lenses mostly used in such articles is strongly curved and may give a totally erroneous impression of relief, in addition to causing severe eye-strain.

Choose a prominent point of detail in the photographic overlap, such as a distinctive white field, and concentrate the attention on it through the stereoscope. Usually two images of the object will be seen. If one of these images is apparently higher than the other, turn the head, and the stereoscope, until they appear at the same level, that is, on a line parallel to the principal point bases. Now attempt to 'fuse' the two images into one by endeavouring to look *through* the table. If this cannot be done, or the two objects can only be fused and kept fused by excessive eye-strain, unpin one photograph and move it parallel to itself (replacing the straight-edge as a guide) until the apparent separation of the images is sufficiently reduced to allow easy fusion. Fusion will often be secured straight away without any later movements of the photographs, particularly after a little practice. When the two images have been fused, allow the eyes to wander gradually over the entire overlap and at the same time keep an open mind as to the relief of the landscape. Such local differences of relief as are occasioned by houses and trees will be readily

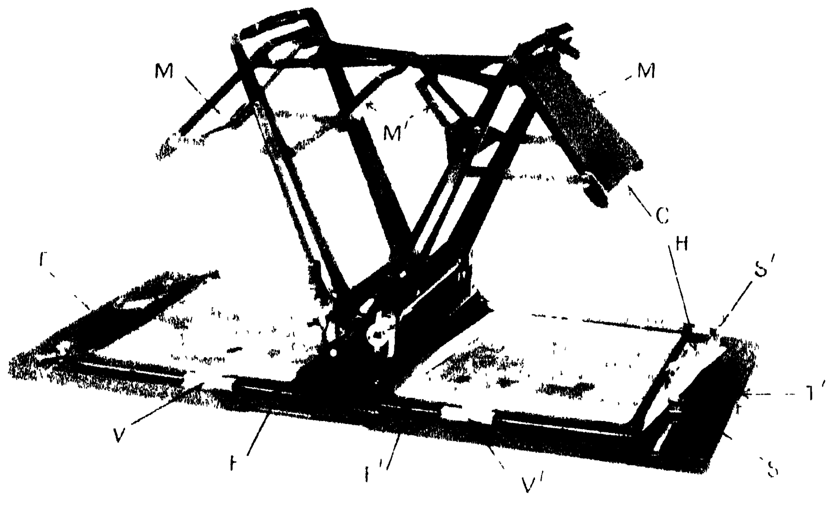

Fig. 3

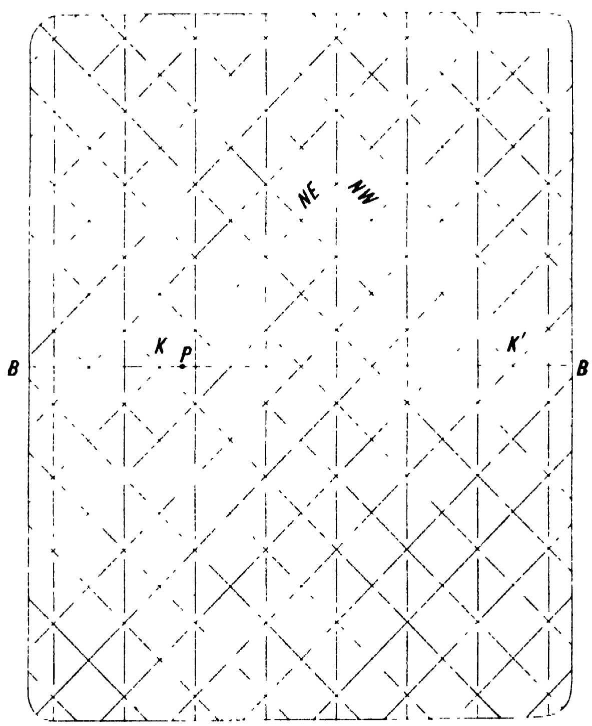

Fig. 4

apparent, but to appreciate the broader topographic features may need practice and the cultivation of a habit of unbiased and systematic examination of the whole area. Once the broad impression of relief is obtained there is no mistaking it.

The distance between corresponding points of detail on the pair of photographs as set for stereoscopic observation (known as their 'separation' and measured parallel to the principal point base) will be found to vary for different points. The separation of corresponding points on the top of a hill is, for instance, less than the separation of corresponding points in a valley. This variation in separation of corresponding points, or parallax, is introduced by exposing the photographs from different camera stations, and gives rise to the impression of relief during the later examination.

To assist in the stereoscopic examination of broad topographic features a special Topographic Stereoscope (Fig. 3) is made by Messrs. Barr & Stroud. The visual system of the stereoscope consists of parallel pairs of inclined mirrors M and M', which form virtual images of the photographs immediately under the eyes and, by thus reducing the separation of the photographic images, makes them easier to fuse. The use of plane mirrors also eliminates the effect of aberrations, which are never entirely absent in even the best prism or lens stereoscopes. Two entirely similar glass plates (illustrated in Fig. 4) carrying a network of lines engraved on the underside are fixed in the frames F and F', and are thus hinged to lie flat over the photographs. These engraved plates are known as parallactic grids, and their purpose is to provide the impression of a reference plane in the stereoscopic field, against which reference plane wider variations in the relief of the landscape will be more readily apparent than they are with no such aid. Being entirely similar (and thus not containing any internal differences of separation or parallax between corresponding lines), the two images of the grids fuse to form an apparently flat plane, whose height or stereoscopic depth above the landscape may be varied by altering the separation of the grids, leaving the two photographs fixed. The entire phenomenon is purely relative. If the grids were viewed stereoscopically with blank sheets of paper under them, then any alteration in their separation would occasion no apparent rise or fall of the fused image, which can only be appreciated when the attention is held by the fusion of the underlying photographs. Although the similarity of the grids should, as stated above, imply their fusion into a flat plane—and usually does so—the same relative interaction of the photographs may result in the grid image being broken up in depth, when the photographic detail introduces disturbing influences. Suppose, for instance, that a grid cross K is placed exactly over a point of photographic detail on one photograph, while the corresponding point of detail on the other photograph lies above the corresponding cross. The separation of the diagonal line NE. is thus greater than the separation of the photographic detail, and its fused image will apparently lie below the fused detail. In the same way the separation of the other diagonal lines of the cross (parallel to the NW. direction) is less than that of the photographic detail, and the fused image of this arm of the cross will therefore appear above the fused detail. In the result, the two arms of the cross are split in depth by the detail.

This property of the grids affords a means of accurately setting the photographs. The principal points P are set under the base lines BB of the grids and the photographs are rotated about them until the corresponding detail on the other photograph of the pair also lies roughly under the base line. A grid cross K near the left principal point is now examined stereoscopically. The right-hand photograph is then finally rotated, and the separation of the grids varied, until *both* arms of the cross appear to touch the ground. The same procedure is adopted in relation to a cross K' near the right-hand principal point for the final orientation of the left photograph. It is important that the cross as a whole should be brought continuously down to the ground as the adjustment proceeds by varying the grid separation, since otherwise the effect is usually lost. When set, the photographs are clamped by means of the screw-clamps S, S' (Fig. 3). The grid plates may be raised off the photographs by hooking the spring clip H to the underside of the mirror at C. A straight-edge may then be placed against the stops T, T' in order to rule up the principal point bases on the photographs to facilitate resetting on any future occasion. A change in separation of the grids can be read off the vernier scales V, V' for the rough measurement of heights as described below. The instrument is collapsible and can easily be shut up into a small case for carriage.

If the (vertical) photographs are tilted or are exposed from slightly different altitudes, corresponding points of detail will not lie at quite the same distances from their respective principal point bases. Consequently, the effect described above of a grid cross appearing split in depth may still be apparent even after the photographs have been correctly set, particularly towards the corners of the overlap. For certain purposes, connected mainly with rapid mapping from the photographs, a quantitative use is made of this property, but for purely qualitative examination it is merely confusing. Once the photographs have been correctly set in the Topographic Stereoscope, the fused grid should therefore be raised above the landscape until the effect disappears. The subsequent examination is much the same as looking at a landscape through a fine-latticed window. If the photographs were untilted and exposed from the same altitude—as is nearly the case—the plane of the grid would be a horizontal plane. The indications of a fixed horizontal thus carried over the overlap offer a ready means of appreciating the general rise and fall of the landscape. It is unnecessary to pay any particular attention to the fused grid for this purpose; it will obtrude itself on the attention of the observer without any special effort on his part, and he may therefore concentrate on the ground features. If the examination is carried out in such a grid stereoscope, it will be unnecessary to rely on such adventitious aids to securing an impression of relief as, for instance, obtaining the correct run of shadows in relation to the lighting during examination. If the photographs are inverted left for right, the resulting inverted or pseudoscopic relief may also be clearly seen in such a stereoscope.

A rough measurement of the difference in height of ground features may on occasion assist a detailed geological examination. This may be calculated from the following simple formula:

$$Hp/l,$$

where H is the mean altitude of flight above the ground, obtainable from altimeter measurements or photographic records during the strip flight;

l is the distance on the photograph in the direction of the principal point base which is *not* overlapped by the next photograph in the strip (see Fig. 2). To reduce the effects of accidental tilts,

it is advisable to obtain a mean value of this measurement from a whole strip of photographs exposed on the same flight at a constant time interval;

and p is the difference in separation of the two points considered. This may be measured most accurately with the parallactic grids of a Topographical Stereoscope. A fused vertical line of the grids is brought alongside one of the objects and the separation of the grids altered until the fused line appears to lie at the same height as the object. Both grid scales are then read and the process is repeated for the second object. Addition and subtraction of the scale readings, in a manner which needs no detailed explanation, will then give the required difference in separation. In place of using vertical lines of the grid, either a NE. line may be used for the whole operation, or a NW. line, or a mean reading may be derived from both. But the use of a NE. line for one point and a NW. line for the other would involve serious error on slightly tilted photographs.

Messrs. Barr & Stroud manufacture precision models of the Topographical Stereoscope which are designed to facilitate such measurements and which are also equipped with such refinements as turn-tables for more rapid setting of the photographs. They are mainly used for mapping purposes, but might nevertheless repay the higher cost on other work if they are required for extensive use.

The simple method of calculating differences of height given above assumes that the photographs are untilted and exposed from equal altitudes, and in practice can therefore only be applied with assurance when the two points whose heights are required are situated close together. The difference in height of two points at opposite extremities of the overlap would usually be in error by about 1 ft. for every minute of tilt, for instance, so that no very useful measurement can be made by these means when there are random tilts up to 2°, as is usually the case, unless the effect of tilt is counteracted by restricting measurement to points appearing fairly close to one another in the overlap. Accurate stereoscopic measurements, moreover, require practice, and should not properly be carried out on the ordinary photographic printing-paper of commerce which is liable to considerable distortion. If much quantitative information is sought, it would therefore be advisable to have detailed topographic maps prepared at this stage from the photographs, and for this purpose it would be as well to enlist the services of a specialized cartographic establishment. The methods employed to produce such maps are outside the scope of the present article.

For the examination of local surface markings occasioned, for instance, by faulting or rock outcrops, a magnified stereoscopic impression, which in this case may be distorted without disadvantage, is usually of value. A very suitable stereoscope for this purpose may be improvised from two similar high-powered magnifying glasses held in retort stands. The eyes should be placed over the inner halves of the magnifying glasses. No very accurate setting of the photographs is required for such local examination, although the usual precautions should be taken to choose the correct left and right photographs to obtain the natural run of shadows, and to ensure a very rough orientation. It may be found necessary to place the two photographs so close together that there is a risk of obscuring one photograph by the other. In that case the unwanted inner portions of the photographs may be passed down through a slit in the table, or in a box on which the photographs are placed.

Mosaics

A single overlap of air photographs on the scales commonly used for geological examination covers only a square mile or so of country. It is with a view to extending the area of ground which may be examined simultaneously that various attempts are usually made to compile the photographs together into a 'mosaic', by joining them together so that the detail is more or less continuous over the join, and pasting down photographs so joined on a large sheet of material such as Bristol board. To obtain the best continuity of detail across the joins, it is usual to cut adjacent photographs across the area of their overlap. Consequently, it is not possible, as is sometimes suggested, to obtain stereoscopic impressions by examining portions of the mosaic in conjunction with a loose photograph. Nevertheless, a mosaic may serve a valuable purpose as a comprehensive index, showing in approximately relative position the information gleaned from stereoscopic examination of a duplicate set of photographs. It may also indicate, for more detailed study on the separate overlaps, certain geological structures which cover too wide an area to be picked up in the first place on separate overlaps.

It will be realized that a perfect join between two adjacent photographs can only be obtained when the photographs have the same uniform scale, and it has already been pointed out that this is only the case when the photographs are untilted, are exposed from equal altitudes, and are photographs of flat country. Variations in scale introduced by tilts and unequal altitudes are not likely to be very significant for the present purpose if the flying and photography are carried out by a properly trained and practised photographic crew. It would be unusual, for instance, to encounter tilts exceeding 2°, with a corresponding non-uniform scale variation between one side of the photograph and the centre of the order of 2%; while an accidental increase or decrease of 100 ft. in a flying altitude of 10,000 ft. would only occasion a departure of 1% from a mean uniform scale. By arranging to utilize only the central portions of the photographs for the mosaic, the effects of such scale variations may easily be reduced to within tolerable practical limits. But it is otherwise if the country is not fairly flat. A variation in relief of the ground of only 200 ft. or so, in the case of photographs exposed from 10,000 ft., would superimpose an error equal to the probable effect of tilt and variation in flying altitude combined. This source of variation in scale is also counteracted to some extent by utilizing only the central portions of the photographs, but if the variations in relief are at all considerable, it may well be impossible to compile a mosaic to serve any useful purpose at all. Accuracy in the measurement of distances on the completed mosaic has nothing to do with this question. If the scale variations are excessive, prominent detail may either appear twice on the compilation or not at all, and there is a limit to the extent to which this failing may be cloaked by judicious cutting of the photographs so as to throw such omissions and duplications into unimportant areas. An accurate plan of the area may not be required, but a reasonably complete and unique representation of the ground certainly is required for any purpose.

In such cases, the only solution of the difficulty is to give

up the production of a mosaic altogether in favour of the compilation of a drawn map. Methods exist whereby this may be done rapidly—although it would be advisable to seek the co-operation of a competent cartographic establishment to do it—and the result will have the advantage that distances may be scaled off it with some assurance. Even the largest scale conventionally drawn maps cannot show as much detail as appears on the original photographs, but this disadvantage—if disadvantage it is to non-specialized map-users—can easily be offset for systematic geological examination by using the map in conjunction with stereoscopic examination of the original photographs.

The compilation of a large mosaic, even of flat country, is a skilled operation which would usually best be undertaken by the company or organization employed for aerial photography. The principles are simple enough, but their application needs practice. The desirability of choosing the central parts of the photographs for final display in the compilation, and trimming off the overlaps accordingly, has already been mentioned. Another property of air photographs of which use is made is that directions from the principal point are to a large extent unaffected by scale variation—whether due to tilt or unequal altitude or relief—so that a join of two photographs by making the two principal point bases coincide will be mainly correct and will facilitate the addition of further photographs to the compilation. A last principle is that no photograph or portion of a photograph should be finally stuck down until there is no possibility of having to move it to secure a better fit of other photographs. It is impossible to obtain perfect joins everywhere, and if any attempt is made to do so, the trouble will merely be pushed ahead and made worse at a subsequent join: the aim should be to distribute imperfections throughout the compilation.

Interpretation of Air Photographs

The vertical air photograph records an unfamiliar view of the ground which requires some little practice and experience for its interpretation. Such practice, which may best be obtained by studying air photographs of familiar ground, is indispensable. A few general principles may be conveyed in print as a basis for practical study, but no amount of printed description alone will enable very much information—particularly such specialized information as is required for oil geology—to be obtained from the photographs. Generally speaking, the more practised the geologist at reading photographs of different types of country, the less will he need to supplement his observations by field work, although a certain amount of field work will always be necessary, if only to seek confirmation.

Stereoscopic examination should be considered a *sine qua non*. Air photographs suffer from quite enough limitations, which cannot be overcome, without the gratuitous sacrifice of the third dimension in reading them. It is true, but quite beside the point, that various 'lucky strikes' have been made by observing surface markings on an odd single photograph and subsequently prospecting this area on the ground. One hears most of these cases when they are successful, and nothing of the occasions when the markings are due to a peculiar system of native agriculture or grazing, or even to scratches on the film emulsion. The trained geologist will not, of course, neglect to note such features for his subsequent field examination, and will be guided to them by the photographs, but he will no more dispense with the stereoscope in his preliminary field examination than he would willingly use an uncontoured map for the geological interpretation of land forms. The use of a stereoscope, moreover, solves such minor difficulties of interpretation as confusing an object with its shadow, and will dissociate film scratches from the landscape altogether.

An air photograph must always be read in relation to its scale. Unless this is done totally erroneous conclusions may be drawn. Faulting, for instance, will usually appear as a straight and more or less continuous line. On very small-scale photographs the same sort of image would result from a road or straight track, partially obscured by trees, or even a railway. A little calculation and reflection will, however, show that the road or railway on photographs of known scale would have a certain width, and either may be ruled out if that width does not actually appear on the photograph. No ordinarily intelligent person would attempt to read a map of unknown country without first getting some idea of its scale. To dispense with any idea of scale in reading an air photograph is far worse, because the photograph is a much more detailed and faithful representation of the ground than any map. It would be useless attempting to measure the width of a road, for example, on any but the largest scale map, because the width will have been exaggerated or 'generalized' in the interests of clarity, yet on the photograph it is shown in its correct natural proportions.

The smallest size of object which will show up on a photograph depends on the nature of the object and on the quality of the photograph. A small brilliant object reflecting light straight into the camera will often show up when a larger dull one will not. But as general rule it may be assumed that an object will not be distinguishable from its surroundings if any dimension of the photographic image is less than about 0·002 in. An image much smaller than this would be confused with the grain size of the photographic emulsion or would not be resolved by the lens. This implies, of course, that it is little use looking for objects less than 2 ft. wide on 1/10,000 photographs, although smaller objects may sometimes be identified by larger features which are always associated with them. The same reason applies to the appreciation of stereoscopic depth. If, in the formula given above, we substitute 0·002 in. for p, and for the sake of example assume that l is 3 in. while H is 6,000 ft., we find that an object must stand out more than 4 ft. above its surroundings if the fact that it does so is to be appreciated by stereoscopic observation. To examine objects as small—or as low—as this, magnification would be necessary, but no amount of magnification would render smaller—or lower—objects visible. Moreover, the definition of the photographs would need to be good for these limits.

It has already been mentioned that an observer at high altitudes is usually bereft of colour sense, and the same applies to the camera, which as a further means of falsifying colour values is supplied with panchromatic film and a yellow filter, the object of which is to cut out actinic light directly reflected from the intervening haze. Colour, in fact, has very little effect in fixing the 'tone' or shade of white, grey, or black in which an object will appear in the photograph. The deciding factor is the amount of light, of whatever colour, which the object reflects into the camera, and the characteristic which most affects this is the *texture* of the object. Smooth surfaces will usually be dark in tone for the reason that they do not scatter light and—barring an accidental direct reflection into the

camera—which sometimes happens—will therefore most often reflect all the light away from the camera. Rough surfaces will have an intermediate tone depending on the amount of light scattered by them, a more or less fixed proportion of which will reach the camera irrespective of the direction of the incident light. Nevertheless, colour is not altogether non-effective. Chalk, snow, and sand will almost always show up white, whatever the direction of the reflected light. An air camera is very sensitive to differences in reflecting power, and this is perhaps one of its most valuable characteristics. Minor differences in the reflecting power of soils, whether due to change in the underlying geological structure or to the hand of man—in recent or remote ages—show up with amazing clarity. All that can be definitely established from the photograph is that there is a change in reflecting power, which may or may not have a special significance for the purpose in view; more definite conclusions must await examination on the ground, which is narrowed down, but not replaced, by the use of air photographs. The latter, in conjunction with later field work, has, however, often led to the discovery of structures or structural changes which had been missed altogether by ground work alone.

The correlation of vegetational changes with changes of geological structure is also a fruitful field, and the former are clearly visible within definite boundaries on air photographs, but would otherwise be difficult to obtain. Here again a change in vegetational type or density does not necessarily imply a change in geological structure—much less the existence of oil—but it does indicate an exact locality for further investigation. This further investigation may indeed show that the change is due to nothing more significant than climatic exposure, or to partial clearing or burning in conjunction with native agriculture—or it may lead to far-reaching discoveries.

Structures such as synclines, anticlines, and salt-domes which are associated with definite topographic features are, of course, very easy to pick up by simple stereoscopic examination. The air photograph will not, of course, prove or disprove their association with oil, which must be established by geophysical methods or by boring. But, once again, the field for the latter methods will have been narrowed down by the preliminary photographic reconnaissance.

Other Uses of Air Photographs

After the preliminary photographic reconnaissance, the air photographs, together with any maps or mosaics made from them, should be taken into the field to confirm the conclusions drawn and to clear up any doubtful points. Examination of the photographs will enable each day's journey to be planned in advance so as to secure the maximum amount of information in the shortest time. The photographs, or better a mosaic or map compiled from them, will also serve to record the locality of field observations. Later they will facilitate the location and recording of geophysical work.

The wealth of surface topographic data contained in air photographs and in maps compiled from them has obvious uses in the development of oilfields. The general lay-out of existing communications is given at once. The photographic material in the hands of the civil engineer very materially assists his reconnaissance for the improvement of communications, whether road, rail, or pipeline. The efficiency of engineering reconnaissance carried out by these methods is generally far in advance of the older ground methods, owing mainly to the fact that alternative schemes covering a wide area can all be compiled and reviewed at the same time, in as great or in as little detail as may be required, with the certain assurance that no more profitable alternative can have been missed. This increased certainty and efficiency of reconnaissance leads, as a rule, to lower operating and maintenance costs. The general administration of the fields is also simplified by the provision of adequate topographic information on which an efficient lay-out may be based.

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SURFACE INDICATIONS OF OIL

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Indications of Oil.

SURFACE indications of oil include all those substances commonly associated with petroliferous deposits. The gaseous, liquid, and solid hydrocarbons have the most obvious connexion with such deposits and may be termed direct indications. There are other materials, however, such as salt-water, sulphur and various sulphur compounds, gypsum, and certain types of strata often identified with the source rocks of petroleum, which are not necessarily associated with oil, but one or more of which are so commonly found in oilfields that their occurrence in virgin territory merits examination and close study. These may be termed indirect indications.

In the following description of the various types of oil indications the greatest space is devoted to the direct types. The indirect indications are dealt with more fully in the article by Professor Illing on their significance.

Gas Shows.

The gas from petroleum deposits is, with some exceptions, composed principally of methane. Small quantities of the higher members of the paraffin series—ethane, butane, &c. —are usually present and, in certain cases, sulphur compounds. The occurrence of large quantities of carbon dioxide in association with petroleum is rarer. Seepages of these gases unaccompanied by liquid or solid bitumens are not uncommon.

Recognition of a true gas seepage from petroliferous beds may be difficult, due to the fact that methane in considerable quantities is evolved by decaying vegetation in swampy areas and occurs also in coal and lignite seams. Also, sulphurous gases and carbon dioxide are a feature of some volcanic activities. Such possible sources must therefore be considered and careful examination made to exclude errors in diagnosis on that account.

Gas escaping under water is readily seen. In clear, shallow water with a rocky or sandy bottom it may be possible to see the places from which the gas issues, and there is then little doubt that it has a subsurface origin. In the case of deep or muddy water where the escape is not violent, every effort should be made to trace the seepage to bedrock.

Cases are recorded where the escape of gas is sufficiently strong to agitate large bodies of water to a considerable degree. Thompson [7, 1925], for instance, mentions that boats have been capsized in the Caspian from such a cause.

In arid regions gas seepages, if not violent, are much more difficult to find. Their presence is sometimes indicated by bubbles arising in small puddles. In other cases gas may be revealed by a characteristic odour in sheltered depressions. The presence of sulphur compounds in the gas makes its odour much more apparent. The concentration of gas in depressions may be so great that animals straying into them become asphyxiated. Instances of this are to be found in Central America and elsewhere, the poisonous zone being marked by accumulations of bones.

The escape of gas is often intermittent, due to blocking of the channels along which it passes and the consequent need for its accumulation behind the obstruction until the pressure becomes sufficient for it to break through. Such phenomena are described by Thompson [7, 1925] from the Baku district where violent eruptions of gas commonly take place after several years of quiescence. Earthquakes may also cause the escape of gas in areas where it is not generally found.

In rare cases gas seepages are continuous and of such volume that the gas will burn uninterruptedly for very long periods. The eternal fires at Surakhany are a case in point.

Probably the most spectacular examples of the escape of gas are provided by mud volcanoes. These are due to the escape of gas and water through argillaceous strata, and take the form of conical mounds or of basins full of soft mud in a state of constant agitation. The basin type, of which Lagoon Bouff in Trinadad is an excellent example, is formed where water is abundant and the disruptive and puddling action of the gas gradually erodes the soft strata. The result is a basin which is filled with mud soft enough to flow away when it reaches the general level of the surrounding country. When the mud is so viscous that it does not flow readily, the tendency is to form a cone around the gas vent. In dry regions where heavy rains are uncommon these cones may attain gigantic dimensions. The Boz Dagh mud volcano in the Baku district is 1,000 ft. in height. In other instances a large number of comparatively small cones may form.

The emission from a mud volcano is intermittent. Very high pressures may be built up before an eruption takes place, then, when it does occur, it is very violent. In certain areas in Trinidad the mud resembles a great lava flow and covers large areas. Submarine eruptions have been recorded, in Trinidad and Burma for instance, and the volume of mud ejected has at times been so great that new islands have been formed. Kugler [4, 1933] remarks also on the effect of mud-flows on topography and drainage, saying that in one area in the Cedros Peninsula, Trinidad, there is hardly a normal valley to be seen.

Fossil mud volcanoes, evidence of former activity, are not unknown. They take the form of mud and sand dykes, buried mud-flows, and erratic blocks. They are characterized by very poor grading of the material and the presence of fragments of all the geological horizons down to considerable depths.

Liquid Shows.

The oil in liquid shows varies from a light, colourless oil to black, very heavy and viscous material. The dark, thick oils are the most common type found in seepages and, by their nature, are the most easily recognized. Seepages of very light oil are rare. Some occur in Persia at the White Oil Springs, 38 miles north-east of Ahwaz, where there are two seepages on the crest of a fold and from these about 20 gal. of colourless oil resembling kerosine are obtained per day. The oil was collected by the natives and sold for domestic purposes. Comparatively large seepages of light oil are also found at Lizard Spring in Trinidad, the

oil collecting in the dry bed of a stream during the dry season. Other light oil seepages are found in Venezuela, Colombia, Russia, and a few localities in Europe.

Dark, heavy oils are more easily seen than light oils and they resist dispersion better. Generally there is a tendency towards oxidation and polymerization so that the oil hardens into solid matter. In forest areas it frequently mixes with leaves and fallen twigs, making a dense, black, asphaltic carpet. Seepages of this type occur in the Magdalena Valley in Colombia, and Stutzer [6, 1931] describes one area there as resembling a moor in which asphalt-cemented leaves replace the usual water-saturated peat. The bed of one stream is covered with asphalt, and the twigs and grasses on the banks are smeared with heavy oil to a height of 6 ft.

The seepages at Qaiyarah on the River Tigris, some 35 miles south of Mosul, are very impressive. Large areas are covered with material which shows all gradations from thick, tarry oil to solid asphalt. The heavy oil wells up from numerous small vents in these patches and is accompanied by inflammable gases containing hydrogen sulphide.

Where oil escapes under water its presence is indicated on the surface by an iridescent film. This must not be confused with the film of hydrated iron oxide which is often seen on stagnant water. The iron oxide film is readily broken with a stick, whereas an oil film immediately re-forms after being disturbed. If a seepage is of any size, it will tend to form a thick oily scum on stagnant water. Oil has been recovered from such seepages by skimming or by dragging cloths along the surface of the water and then squeezing the oil from the cloth. It was obtained from the River Ohio in this manner and sold as 'Seneca Oil'. In the case of rivers carrying much silt and clay the oil does not usually remain for long at the surface, but is carried down by the mineral matter. The seepage therefore tends to be localized in those cases. Thompson [7, 1925] records a number of interesting examples of submarine seepages. Such an occurrence off Yucatan in Mexico produced an oily scum on the sea and resulted in the death of so many fishes that troops had to be engaged to destroy them when they were washed up on the shores. Oil 'ponds' off the coast of Texas are mentioned by Fenneman [3, 1906], who states that they are used by coasting vessels seeking quiet water during storms.

In dry, sandy areas the seepages produce impregnated sands from which oil may sometimes be obtained by digging pits. This is more the case with the non-asphaltic types of oils, for with the asphaltic types inspissation produces a hard asphaltic mass as already described.

The surface extent of oil seepages varies between very wide limits. Most of those already described are large, but very many are quite small. The Khaur dome in the Punjab is an interesting example of a producing field associated with a very small seepage. Seepages derived from outcropping sands in Burma are also frequently very small, Craig [2, 1912] stating that even from thick oil sands pools of only a foot or so in diameter are obtained. The small and less obvious shows are usually associated with paraffinous oil which is comparatively easily dispersed by surface waters.

Solid Shows.

Solid shows are very numerous and many are derived from the liquid shows, a fact already noted, and are the result of inspissation of the oil. In general we may consider the following types of solid shows: (1) impregnations, (2) solid asphalt accumulated at the surface, (3) bitumens of deep-seated origin, and (4) wax.

Impregnations are the commonest form of show and are found in clays, limestones, argillaceous limestones, sandstones, conglomerates, &c., with the oil or bitumen in the pores of these rocks. A rock with a considerable oil content may show a tendency to flow under pressure. This is the case with the Athabaska tar sands which, incidentally, are undoubtedly the greatest oil show in the world. The tar sand, which is of Lower Cretaceous age, outcrops for a distance of 120 miles along the Athabaska River in Alberta. In the richer part of the rock the oil is the sole cementing material. Excellent examples of impregnated limestones are to be found in Europe—Val de Travers, Garde, Limmer, &c. They have a bitumen content up to 10% and are used to a large extent for road-making purposes.

Impregnated clays are tough and resist weathering. The adsorptive properties of clays are such that small quantities of bitumen are unnoticed, but as the amount increases the characteristic odour becomes apparent and finally the clay sweats oil. The colour also darkens, and this tends to be more pronounced with asphaltic oils than with paraffinous oils. In addition, well-impregnated sands are tough, and in describing the Athabaska tar sands Clark and Blair [1, 1927] remark that a heavy blow with a hammer makes little impression, although the surface can be picked easily with a sharp tool. Such sandstones tend to weather with rounded instead of sharp corners and edges. Fluctuations of the water-table may flush impregnated sediments completely if the oil is comparatively light, so that the examination should, if possible, be extended to rocks below the permanent water-table. On the other hand, impregnations of heavy asphaltic oils leave black coatings on the rocks even after thorough flushing.

A very simple test may be applied to identify impregnated rocks. A sample of the rock is powdered and warmed with a solvent such as benzene or chloroform, which is afterwards poured on to a piece of blotting-paper and allowed to evaporate. If oil is present in the rock, it will leave a stain on the paper. In some carbonaceous shales resins are present which may give a false show with this test. They may be distinguished, however, by their high degree of solubility in alcohol in contrast to the low solubility of bitumen.

Solid asphalts accumulating at the surface are found wherever inspissation of seepages of asphaltic oils takes place. They have already been described to a large extent in the section dealing with liquid shows. Frequently these asphalts contain considerable amounts of mineral matter picked up before the mass had hardened and they tend to spread out concentrically from the seepage. The 'chapapote' of Mexico is a thin bituminous veneer formed in this manner. The Bermudez pitch lake in Venezuela, on the other hand, is a comparatively pure bitumen contaminated with only a little vegetable matter. Other noteworthy occurrences of such asphalt deposits are to be found in Iraq, Colombia, California, Russia, Mexico, and Trinidad. Very interesting collections of skeletons of extinct animals have been obtained from some of these deposits, the animals having strayed into the sticky mass and been engulfed.

The famous Trinidad pitch lake is of a different type from those just mentioned. It is not an ordinary bitumen, but an emulsion of about 40% bitumen, 30% silty clay, and 30% water. The pitch occupies a depression of some 127 acres in extent and in the centre it is soft, and sulphurous gases escape from numerous small vents. Removal of the pitch has caused lateral flow and subsidence near the edge. On one side of the basin there is a depression which was

originally an overflow channel, and much pitch has been extracted from this. The level of the lake is now slowly falling due to continued excavation.

The deep-seated bitumens are of various types, often very pure, and fill fissures, joints, and fault planes near to petroliferous strata. Some of the principal types are grahamite, uintaite, gilsonite, manjak, albertite, and wurtzilite. They are best described separately.

The type locality of grahamite is in West Virginia. It occurs also in Oklahoma, where there are exceptionally large veins, in Texas, Cuba, Mexico, and Trinidad. Grahamites have a black streak, a conchoidal to hackly fracture, and a high melting-point. They are heavier than water, very soluble in carbon disulphide and chloroform, partly soluble in petroleum spirit, and insoluble in alcohol. Their mode of occurrence is in veins which vary from a few inches to as much as 25 ft. in width. The material in the thicker veins often contains an appreciable quantity of mineral matter. The so-called manjak of Trinidad is really more of a grahamite than a true manjak. It occurs in a zone of complicated tectonics and is found along fault planes. Its melting-point decreases with depth, and also in the deeper levels there is a variety which approaches more closely to the true manjak in type.

Manjak is usually very pure with a dark-brown streak, conchoidal fracture, and specific gravity of 1·1. The type locality is in Barbados, whilst it also is found in Colombia, Syria, and the Dead Sea. In its solubility in various solvents it is similar to grahamite. Uintaite or gilsonite resembles manjak, but has a slightly lower specific gravity. It is restricted in its occurrence, being found only in Utah and Colorado as vertical veins which may be as much as several feet in thickness.

Albertite, a lustrous, black, bituminous substance with a conchoidal fracture, is characterized by its infusibility, insolubility in carbon disulphide, high percentage of fixed carbon, and low oxygen content. It is found in veins in Lower Carboniferous shales in New Brunswick, there being one principal vein with minor off-shoots. Similar material has also been found in Africa and in Tasmania. Wurtzilite resembles Albertite in its infusibility, but it is slightly soluble in carbon disulphide. It occurs in thin, steep veins in a limited area in Utah.

The typical occurrence of mineral wax or ozokerite is at Boryslaw in Poland, where it is mined and forms a very important product. It is found in fissures and veins in Miocene strata above the great Boryslaw overfold and acts as a cementing material for the breccia filling those veins. It is yellow to dark brown in colour and apparently is derived from the very paraffinous oil contained in the underlying strata. The thickness of the veins is very variable. Other occurrences are known in Russia and the United States. Somewhat similar material is found in association with lignites, and care must be taken not to confuse this with ozokerite.

Indirect Indications.

Sulphur occurs commonly as gaseous compounds associated with the gas from petroliferous deposits and as such has already been mentioned. It is also present as dissolved hydrogen sulphide in oilfield waters in many parts of the earth. Such waters are readily distinguished by their odour and also in many cases by a milky appearance which may be due to precipitated sulphur. Sometimes these waters are quite hot, and brilliantly coloured algae may exist in them. Brines are also commonly associated with oil, and seepages of such brines may leave deposits of salt on evaporation.

Rock-salt in the form of salt-domes is sometimes connected with oil-pools, but such phenomena are rarely observed at the surface. In south Persia and in the Dead Sea, however, cases of the salt penetrating to the surface are known. Saliferous clays are also associated with oil measures, and important examples of these are to be found in Roumania and Poland. Deposits of gypsum occur in petroliferous areas in Persia. This has been described by Lees [5, 1933] as soft, powdery gypsum, white at the surface but brown beneath, and containing crystals of sulphur. In many areas it is accompanied by a development of aragonitic limestone which may be the result of the action of hydrocarbon gases on former gypsum beds.

Amongst the most important indirect indications of petroleum are the various types of strata commonly associated with source rocks. These are dealt with in the article by Professor Illing on the significance of oil indications.

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THE SIGNIFICANCE OF SURFACE INDICATIONS OF OIL

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It is difficult to convey a correct impression of the part played by surface oil indications in the discovery of oil-pools, for conditions vary so widely in different areas that it is impossible to generalize without the danger of being misunderstood. Petroleum occurs far more commonly than is generally realized, although in most cases it is dispersed throughout the rock masses and is of no commercial value. The basis of a commercial field is an accumulation of oil and gas in such form and in such quantities that their extraction becomes profitable. This combination of circumstances is not so common.

It must also be remembered that an active oil or gas seepage is in reality a leakage from a reservoir below, and therefore the latter has been perforated and is being depleted. This seepage may represent the first or last stages of such depletion, and the significance to be attached to it will depend largely on this consideration. Unfortunately it is not usually possible to decide this from the seepage itself, and the problem has to be attacked by other methods.

There are many oilfields which were first discovered as a result of the attention drawn to them by their associated seepages. There are, on the other hand, numerous areas in which the seepages are just as good and yet all efforts to discover oilfields in their vicinity have been fruitless. Finally, there are many areas where there are numerous large oil- and gasfields completely lacking in all the normal surface indications of the presence of oil.

It is, therefore, clear that the discovery of an oil show is but one step in a long investigation which demands careful consideration of all the evidence before its significance can be properly assessed. Its relationships to the commercial pool are by no means as direct as are the relationships of the outcrop of a mineral lode to the lode itself. Oil is mobile and readily dispersed, and there is usually a considerable distance between the seepage and the parent reservoir rock.

As already indicated, there is no necessity for an oil-pool to have any surface indications; indeed, a perfectly enclosed oil reservoir should not have any, although there may be indications from other rocks in the neighbourhood. In the Palaeozoic oilfields of the United States little or no attention is paid to surface indications, firstly because they are uncommon, and secondly because the factors considered in the search for oil-pools are almost entirely structural. Among the oilfields of Tertiary age seepages are far more common, for in most cases the structures involved are more highly deformed, denudation and oil dispersion more active, and the oil-bearing strata more clearly exposed. This leads to a more rapid dispersal of oil and gas, but as the rocks are much younger the time interval has not been sufficient for complete dispersal. The same truth may be expressed in another way by saying that among the Palaeozoic oilfields, the only ones which have been preserved over long geological periods are those which were exceptionally well covered and have no active seepages in their neighbourhood. The oilfields of Pennsylvania, Kansas, North and Central Oklahoma, and the Bend Arch district of Texas are good examples of such fields. There are, of course, some small seepages where the oil-bearing rocks in these areas approach the surface, but they are relatively insignificant and are not usually in the zone of the prolific fields.

Contrast this condition with that of the oilfields of Venezuela, Burma, or Iraq, where there are very few oil-pools which have not seepages at the surface and where the rocks are so folded and faulted that erosion has bitten deeply into the structures and the fluids within the latter have suffered considerable readjustment and loss. The absence of seepages in rocks so well exposed would be highly unfavourable. Should the geological condition, on the other hand, be such that the oil and gas horizons are covered by impervious rocks, then the lack of seepages would not deter the geologist from testing suitable structures.

The following conditions summarize briefly the general relationships between oil shows and oil-pools:

1. Oil and gas are very widespread in nature, but most of the occurrences have little commercial significance.
2. An active seepage indicates loss of oil or gas. Before reaching optimistic conclusions, care must be taken to determine the extent of depletion of the reservoir.
3. Oil shows are more common in the folded rocks of Tertiary age and they can be used more safely under such conditions.
4. Protection from dispersal of the oil is more necessary in the older rocks in order to preserve the field for long geological periods. In such areas oil shows are less obvious and their absence is not a discouraging feature.

Types of Oil Indications

Gas Shows.

Care is necessary first of all to determine that the gas is of the type associated with petroleum (so-called 'natural gas') and not marsh gas or the gas from carbonaceous strata. Chemically these gases may be indistinguishable, although some natural gases contain higher homologues of the paraffin series as well as methane. Normally the pressure and volume of natural gases are much higher than those of gases of other origin, and such phenomena as mud volcanoes are largely restricted to areas where they occur. There seems to be no reason, however, why other gases should not sometimes produce similar phenomena.

Natural gas has low density and great mobility, and when under pressure it is capable of migrating to great distances. Only unbroken and very impervious rocks or, alternatively, water-saturated rocks under pressure are able to prevent this movement. Fractures, such as joints and faults, form avenues of escape for the imprisoned materials. The distances of such migration across the bedding may be very great, in some instances amounting to as much as many thousands of feet. These excessive movements sometimes carry the gases far from the original reservoir, and care is therefore necessary in the location of wells on such evidence. There are also many cases of clays which are very gaseous but contain no reservoir rocks. Such clays are well known in the coastal areas of Colombia and they give spectacular gas shows, but have not led to successful drilling.

Some accumulations of commercial value contain gas alone, so that a gas seepage does not necessarily indicate the presence of oil. This dissociation of gas and oil occurs in all types of strata, but its development is best exemplified in the United States, where many fields are developed solely for their gas.

In spite of these cases many gas seepages, with or without oil, have been the precursors of large oilfields. Such seepages have the important advantage that they normally represent the early stages of fluid dispersion, for the gas occupies the highest position in the reservoir, and though the oil below may have suffered a loss of pressure, it is still largely intact.

Oil Shows.

The possibilities of confusion between oil and other substances of similar physical appearance may not be so common as in the case of gas, but oily materials may be produced by contact metamorphism of coals and allied substances. Such occurrences are common in many of the British coalfields, particularly in South Scotland and Northumberland where there are igneous intrusions. The Karroo beds of South Africa contain examples of gas and oil formed by the dolerite intrusions heating the coals and carbonaceous shales. The residual coal has lost much of its volatile matter and the oil and gas have accumulated in the rocks near by.

Oil shows are usually in one of two forms, an impregnation of a rock or a seepage of free oil. The former may consist of small quantities of oil in a fine-grained rock such as clay, shale, or compact limestone, or it may be oil in the larger pores of a reservoir rock such as sand or limestone. Oil-impregnated strata may indicate a general case of stratigraphical oil impregnation, possibly signifying a source rock. On the other hand, some fine-grained rocks become so fissured by earth movements that they become impregnated throughout a considerable zone although the oil is really in a state of slow movement. Such cases can only be differentiated by careful field study.

Free oil seepages are usually associated with oil movement along fissures or with the escape of oil from a reservoir rock with or without the aid of water. Such free oil tends, therefore, to support the view that there are rocks in the neighbourhood which not only contain oil, but are sufficiently permeable to give it up. This is not always a safe conclusion, for water will wash oil out of exceedingly fine clays in the zone of weathering, though the process is slow and the free oil not very abundant. Most oil seepages are rendered obvious by the fact that the oil is floating on water. The oil from such seepages does not usually travel far, even in streams, it being carried to the bottom by becoming attached to mineral matter.

Some exceedingly light oil seepages may be the result of condensation from wet gases which have travelled considerable distances before reaching the surface. As a general rule an oil loses its lighter constituents near the seepage, so that the oil underground may differ considerably in its properties from that in the associated seepage. The difference is displayed most markedly in some asphaltic oils which change to heavy tars, or even asphalts, in the shallower zones of an oilfield.

Solid Shows.

There is every gradation from the liquid to the solid state in oils and, as indicated above, the oils in many fields are changed gradually to asphalts either by evaporation and oxidation, or by changes produced by bacteria present in the invading waters. Seepages of asphaltic oils which harden at the surface into asphalts have the true significance of liquid shows. Solid veins of asphaltic material or ozokerite sometimes represent channels along which oil has migrated during periods of excessive trans-formational movement. It is probable that in these cases the migrating liquid had a considerable admixture of oil which was absorbed into the walls of the surrounding rock, or, in the case of ozokerite, that the wax was filtered out of a waxy oil during its passage. As a general rule the occurrence of veins of solid hydrocarbons appears to be the least valuable of oil indications, for many of them undoubtedly represent the last traces of former oilfields. Their vein-like form can only have been produced in rocks so disturbed as to be no longer impervious, and in such cases oil preservation over long periods is unlikely. However, there are exceptions which show how difficult it is to generalize in such matters. As examples of these exceptions the ozokerite veins at Boryslaw and the Grahamite vein of Virginia may be cited.

Indirect Indications.

There are a number of other features associated with oilfields which may have considerable significance in the search for oil-pools. One of the most important is the efficiency of the reservoir cover rocks as a protection against dispersion of the fluids contained therein. This is indicated by:

(*a*) A condition of high pressure in the formation.
(*b*) A considerable degree of salinity in the entombed waters.

Both of these conditions are favourable features and it is exceedingly rare to find any important oil-pools in a region in which these are not satisfied. The first can only be discovered by drilling, and even then only by taking adequate precautions. The presence of salt-waters, on the other hand, may often be proved in outcropping formations and in water springs, although it is also best studied in wells. Almost all oil-pools are underlain by water, and in almost all cases this water is saline. In the shallower fields the brines are of a mixed type, but in deeper sands they tend to be more concentrated, the principal salt being sodium chloride. Such deep brines are probably entombed sea-water, or 'connate water', as it is termed. Their presence in marine formations indicates a freedom from water flushing which is a feature favourable to the preservation of oil. Care must be taken, however, to exclude from this consideration brines derived from the leaching of salt masses.

The occurrence of rock-salt itself may be of significance. In the form of salt-domes it is associated with structures favourable to oil concentration and also, when in the form of a sheet of plastic salt, there can be little doubt that it acts as an efficient barrier to upward migration.

The nature of the formations associated with oil is highly significant. The dominant lithological type is clay, or marly clay, although in some cases it is a limestone. The clays are normally dark in colour, whereas the limestones are grey to white. Such rocks, however, cannot provide commercial oil-pools unless they contain porous reservoir rocks of sufficient size, or unless they are themselves rendered porous by jointing and fissuring. Minerals such as pyrite and gypsum tend to occur within them, the former probably indicating the anaerobic conditions.

under which the formations were laid down. As a whole, these features are generally ascribed to the strata which are termed 'source rocks', and their presence in most oilfields supports the conclusion that the oil was formed in them. There are, however, notable exceptions to these generalizations on colour, as, for example, the red Permian oil rocks of Texas and the Devonian of Pennsylvania.

Relationships of Seepages to Structure and Erosion.

It has been emphasized that oil shows are either impregnations or seepages. In any movement of oil or gas to the surface two conditions are clearly necessary, a driving force and a permeable zone through which the fluids can travel. The driving force is supplied by the gas and oil pressure, or by the movement of water currents. The permeable zone is supplied by the porous rocks and by fractures such as joints and faults. Hence, while an impregnation of a compact rock may occur under almost any conditions, the impregnation of a porous rock or a free seepage normally tends to occur under certain structural conditions. Three of these conditions can be treated as typical of most seepages.

1. **An Outcropping Oil Reservoir Rock.** An outcropping oil sand or limestone will show oil impregnation if it be asphaltic, but may lose all of its oil in the parts above the water table if it be paraffinous. The flushing action of meteoric water usually removes the oil from the rock and it collects in hollows along the outcrop. Streams may cut across the oil-bearing strata and wash out some of the oil, but this is rapidly deposited on the stream bed unless the water is free from sediment.

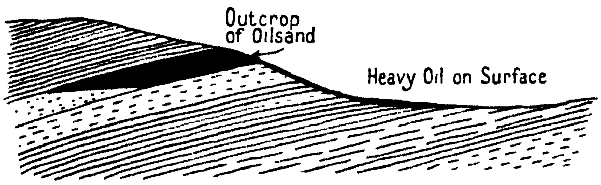

FIG. 1. Seepage from an outcropping oil sand.

Such an outcropping formation cannot be considered as a favourable zone for drilling since it has lost its pressure and much of its oil. At the most only a few pumping wells can be expected, unless there be an impermeable zone down dip, due to faulting, cementation, or lenticularity, which may have protected oil below it from dispersal. Whilst, however, there is little hope of obtaining commercial production from the outcropping sand, it nevertheless indicates that the original structural conditions were favourable to accumulation. Deeper drilling to lower horizons may therefore give good production. The ultimate significance of such a show obviously depends on the nature and thickness of the beds below, and only careful stratigraphical studies and field mapping will give the required data.

2. **Oil Seepages associated with Faults.** Faults may not only provide zones of movement for the oil, but, conversely, they may also limit movement in porous rocks and thereby cause accumulation on one side of the fault-plane. Seepages along the outcrops of faults are common phenomena and are always worthy of close study. The linear relationships of such seepages and their position on the geological map give a clue to conditions underground. On the other hand, structures of this type are usually complicated and variable, so that drilling must be undertaken with circumspection and several initial test wells may be required.

3. **Seepages through the Cover of a Closed Reservoir.** As denudation proceeds the cap-rocks become so thin that they are unable to hold the gas and oil in the reservoir formations. This is usually indicated by an increase in gas and oil shows over the highest portions of the structure. Should it be only the uppermost horizon of an oil-bearing series which is thus being uncovered, great possibilities

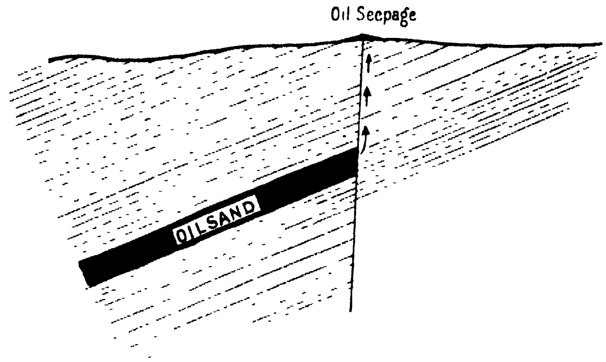

FIG. 2 Seepage along a fault plane

may still remain in the lower strata. The ultimate value of the pool, therefore, must depend on the thickness of the oil-bearing series still uncovered. This illustrates the point, which is true of all the three cases cited, that the evidence of stratigraphy and structure is always required to assess the value of an oil seepage.

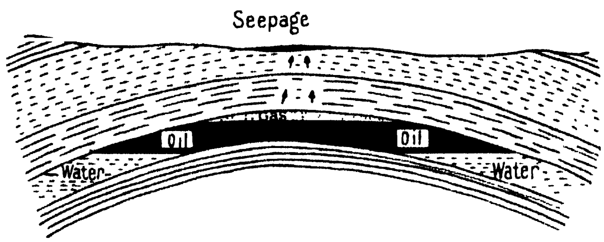

FIG. 3. Seepage through the cover of a closed reservoir.

From the foregoing it may be assumed that the true significance of any specific oil show cannot be obtained by casual inspection. The relationships of the show to the structure must be obtained by careful mapping. The nature and size of the oil reservoir rock should be determined by stratigraphical studies which may require prolonged regional investigation. Then, with those problems solved, the geologist may be in a position to assess the true significance of the surface indication.

In other words, the search for new oil-pools involves careful stratigraphical and structural studies in which the thickness and sequence of the formations and their structural attitudes are the primary consideration. The presence or absence of seepages in such areas must always be related to such studies as part of the complete investigation. If they are present, their significance must be read in terms of the geological conditions in which they occur. If they are absent, their absence must be reviewed in the light of the effectiveness of the cover rocks to prevent oil dispersal. There is no other safe method of assessing the value of a surface oil indication.

NATURE AND SIGNIFICANCE OF SEDIMENTARY VOLCANISM

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IN the following brief account of sedimentary volcanism the writer has endeavoured to convey a clear picture of the subject under review rather than to discuss the literature available on migration of oil and gas.

Source Rocks and Origin of Oil.

Observations and studies in Venezuela and Trinidad have inclined the writer to favour the theory of oil origin advanced by Murray Stuart, Archangelski, Krejci, and others, who consider the source of oil and gas to be black sapropelic mud trapped in depressions and covered by unaerated, stagnant water charged with albumen-reducing, anaerobic bacteria.

Although a small amount of organic substance is found in most recent and fossil marine deposits, such has little practical bearing on the formation of oil, otherwise oil would be found in almost every well-sealed and tilted formation composed of such deposits.

In support of Krejci's theory, one cannot altogether ignore the presence of water derived from planktonic matter during the formation of oil. Such water is rich in halogens and differs from ordinary sea-water. It is unlikely that all oilfield saline waters are such 'by-product water', but one must consider the possibility of a complete absorption of connate water during diagenetic processes. Such 'internal desiccation' is known to be the cause of the dry sands found in oilfields. Their importance during the migration of oil, gas, or even water is obvious.

Migration.

Illing has shown, in a convincing way, that oil migration is at least a twofold process, i.e. primary and secondary migration.

(*a*) **Primary migration** is the movement of fluids from the source rock to the reservoir rock. This movement is mainly completed when compaction ceases, and therefore could be called *Compaction Migration.*

(*b*) **Secondary migration** is responsible for the segregation of gas, oil, and water within the reservoir bed, where the texture of the rock has a decided influence on the distribution of the fluids. As gravity is the dominating factor, it is suggested that this movement be termed *Gravity Migration.*

In order to complete this conception of migration, it is necessary to add a third process to those proposed by Illing, i.e.:

(*c*) **Relief migration** which involves the movement of fluids from reservoir to reservoir. It is obvious that the cause of this movement is pressure relief, the natural tendency of a fluid being to migrate from an area of high pressure to one of low pressure. This migration is not controlled by compaction, neither is gas necessarily the driving force.

This movement, sometimes termed 'Vertical Migration', is started by diastrophism or exogenetic influences. Inasmuch as relief migration follows the line of least resistance in a similar manner to compaction and gravity migration, there is no particular direction along which the movement of the fluids occurs, although the vertical direction is most common. The resultant impregnation generally takes the form of a cone with its apex upwards, and this is typical of relief migration. Excellent examples of such deposits are known in the oilfields of California, Rumania, Russia, Trinidad, Burma, &c. The Rumanian and Baku areas are famous for the occurrence of commercial accumulations of oil in fresh-water and even terrestrial deposits where oil could never have originated.

Where diastrophism causes a revival of the movement of oil from source rocks along newly formed fissures and cracks, relief migration may be mistaken for compaction migration. Such oil is not newly derived from polybitumen but exists in a free state in fine joints and fissures. Replenishment of overlying reservoirs from source rocks may explain some of the occurrences of oil in formations resting unconformably on source rocks, which were compacted and lithified long before the reservoir beds were deposited.

Origin of Sedimentary Volcanism.

In relief migration it is observed that liberation of gas under pressure can cause migration of fluids and even clastic material. Such migration is herein called '*Gas-drive Migration*'.

The lithological, depositional, and orographical features resulting from this activity of gas are comparable with those of pyrogenetic volcanism and are discussed under the heading 'Dykes, breccia, blocks, and mud volcanoes'.

Gas drive becomes identical with relief migration when gas under pressure is liberated by exogenetic influences such as erosion of superincumbent beds, desiccation cracks, or artificial tapping. It is also possible that endogenetic processes are responsible for pressure relief, but, as far as the source of the high gas pressures is concerned, orogenetic forces must be considered primarily responsible. Goubkin, for instance, in a series of illuminating examples, demonstrated the relationship of the mud volcanoes of the Apsheron Peninsula to diapiric folds. In addition to the requisite plastic clay and weak spots in the overlying beds, he considers vertical pressure to be essential to the formation of diapiric folds and plugs. On the other hand, Cizancourt and others concluded that diapiric structures are the result of tangential pressure with plastic clay acting as a lubricant for the laterally gliding masses, resulting in incongruous, and finally, disharmonic folding ('Abscherung' or 'Décollement').

The physical properties of salt are primarily responsible for the facile injection of salt formations, causing salt-domes and plugs. Such tectonic features cannot be formed by ordinary clay which lacks the physical properties of salt. A gas-saturated clay lubricated with oil is, however, much more prone to such injection than is pure clay. If, in addition, the continuous generation of gas is possible through geochemical and perhaps biochemical processes, the expelling force would become an integral part of the movement. Although it is not suggested that such gas pressure is responsible for the formation of uplifts, it is possible that gas-saturated clays and shales, especially

when coated with oil, will behave in a manner similar to a salt mass, should conditions permit.

Whenever incompetent masses of bituminous clays are squeezed up through an overlying series of competent beds, whether by lateral or by vertical pressure, the movement can only occur along a line of weakness, for preference, along an open fault. Although faults have always been considered convenient passages for escaping gas, and thus for the origin of mud volcanoes, it would be interesting to analyse the relationships of mud volcanoes to local underground and regional tectonic conditions. It is, for instance, not quite clear whether or not NNW.-SSE. directed transverse faults (Blattverschiebungen) are the original cause of the obliquely trending folds with diapiric cores known in the Apsheron Peninsula.

Tension cracks formed during orogenetic movements are natural passages for escaping gas. Crestal collapse of anticlines causes revival of such movement along the lines of fracture. Open tension faults and gaping joints undoubtedly play a more important role than is generally admitted in the literature.

A bore-hole which produces sand or heavy mud which has passed from a neighbouring hole can only do so if fine fissures or small cavities are present. Conversely, the heavy drilling mud of a well can only disappear into the formation when cavities are present. The fissures may be as fine as those of the compact Iranian Asmari limestone.

If cracks are formed in competent beds above an oil- and gas-saturated clay or a highly charged reservoir of unconsolidated sand, it is natural that the clay or sand will be forced into these cracks either slowly or in an explosive manner. The texture of the resulting dykes of clay, mudflow, breccia, or sand indicates the velocity of intrusion.

Dykes, Breccia, Blocks, and Mud-volcanoes.

Fissures several miles long and hundreds of feet in depth are known to exist in petroliferous areas. They generally correspond to cross and transverse faults oblique to the main direction of the orogenetic force. Thrust planes with plastering material have a sealing effect, and prevent migration of fluids. Fissures filled with bitumen alone or mixed with country rock are described from various oilfields and even from the oil shales of Scotland.

The occurrences of 'hydrocarbon dyke' fissures filled with materials such as ozokerite or asphaltites received early attention due to their economic value.

Sandstone dykes are probably the best known amongst the fissures containing clastic material. Such sand dykes soaked with inspissated oil occur in Trinidad and attain a thickness of 10 ft. In addition they carry edge-worn pieces of fossiliferous rock derived from beds stratigraphically several hundred feet below. In other parts of Trinidad, *clay* and *silt* dykes are proved by their foraminiferal assemblages to be derived from beds which occur stratigraphically as much as 5,000 ft. deeper.

Considerable interest has been attached to the *pebbly clays* or *breccias* of various oilfields. Many geologists have been inclined to consider these breccias as evidence of extensive thrust movements and as being expelled by orogenetic forces at the outcrop of the thrust plane. Hence some Russian geologists have termed them 'tectonites'. There is, however, no doubt but that they simply represent mudflows composed of angular fragments. Some brecciated clay dykes, and particularly the corresponding mudflows, resemble *tillites* and may be mistaken for such, especially if striated pebbles are present. Krejci notes that such striated pebbles occur in Roumanian mudflows.

In Trinidad, mudflow breccias are known to attain thicknesses of several hundred feet. They may be composed of sub-angular pieces of upper Eocene marl mixed with fragments of younger beds, but actually they are found interbedded in productive Miocene sands and silts several thousand feet above their provenance.

The practical significance of the occurrence of older formations amidst younger ones becomes clear when it is realized that drilling has often been discontinued on the assumption that such rocks have been reached and that they represent the unproductive basement, yet later exploratory drilling has shown the same younger formation, with rich oil deposits, underlying these mudflow intercalations.

In the Guayaguayare field of Trinidad, even Cretaceous foraminifera have been found in injected clay veins amidst Miocene silts and sands.

Once it is admitted that smaller fragments form a part of mudflow, there is every reason to expect larger components, and the writer has demonstrated this to be the case in Trinidad, where blocks weighing 100 tons or more have been transported by mudflow. Moreover, there is every likelihood that the so-called 'erratic blocks' of the Tintea area of Roumania do not belong to fanglomerates as suggested by Krejci, but represent the residue of large masses of mudflow, the fine parts of which have been washed away. Goubkin mentions similar phenomena in the Apsheron Peninsula, where blocks of Mesozoic beds are found in mudflow extruding from Pliocene formation.

The transport of such large blocks is intimately connected with gas-drive migration and occurs as follows:

Liberated gas derived from the oil-mother rock or from a reservoir forces its way into a fissure filled with water, or one which is, at least, in communication with water sands. By the churning action of gas-agitated water, the clay of the walls forms a viscous mud. Through further action of gas and water, large blocks of the wall become engulfed. The movement may temporarily cease due to the weight of mud formed, but will commence again either by further release of pressure or by the pressure of geochemically-produced gas which has continued to accumulate. Finally, the mud carries the blocks to the surface where they may be expelled explosively or simply carried into the mud cone where they remain. Subsequent changes of the vent and denudation of the mud lead to the accumulation of the blocks on the original surface on which the mud cone rested.

The nature and occurrence of *mud volcanoes* has been sufficiently described, so that further comments are unnecessary. It may be mentioned, however, that, under certain circumstances, mud may be accumulated in downward-tapering conical-shaped basins. The mud of such basins can be subjected to the churning action of gas to such an extent that it becomes completely gas-cut and frothy. Through the rotation of every particle of non-collôidal material, a mud of semi-pisolitic structure incorporating hydrocarbons is formed. When hardened, this floats on water and burns like an oilshale. The rim of the Pitch Lake in Trinidad is characterized by this type of pebbly clay.

The *life of mud volcanoes*, hence the duration of gaseous exhalations, may last thousands of years at one particular spot. The term 'eternal fires' given to some of the gas seeps near Baku, and the discovery of Megatherium bones in a mud volcano in Trinidad, are unquestionable proofs

of the great age of such volcanoes. The amount of gas issuing into the air from a single major gas seep must be enormous.

General Conclusions.

Although it is still a moot point as to how much pressure subterranean gas is able to develop, one cannot deny the important role played by gas in the formation of diapiric folds and dykes, the transport of fluids, mud, and blocks, and finally in the formation of mud cones and basins on the surface.

The types of rocks and other features arising from the activity of gas are included under the term 'Sedimentary Volcanism', which is itself intimately connected with the relief migration of fluids.

Finally, it may be remembered that in 1861 Andrews considered that anticlines contained oil because they were full of fissures. This conception is by no means in conflict with the views of adherents of the allothigenic nature of oil accumulations, though it may offend the ardent supporters of the view that oil in commercial quantities is essentially authigenic.

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APPLICATION OF PALAEOGEOLOGY TO PETROLEUM GEOLOGY

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PALAEOGEOLOGY is defined as the science which treats of the geology of ancient time. Palaeogeology bears the same relationship to palaeogeography that geology bears to geography. It requires that one place himself—mentally—as if he were at some point in geological time and then consider the geology of the particular area as it existed *at that time* and prior to any later geological history.

There are several methods by which palaeogeological reasoning is applied to the problems of petroleum geology. The basis of all such reasoning, however, is that whatever laws are found to operate to-day in the origin, accumulation, and behaviour of oil and gas must have operated in a similar manner in past geological time. Palaeogeology is the consideration of these phenomena as they occurred under ancient geological conditions in the light of our present knowledge. Some of the methods of palaeogeology follow.

Palaeogeological Maps

Palaeogeological maps show the areal geology of an ancient surface. They are constructed by plotting the formations which are found in contact with the base of the key or datum horizon, and as the control becomes sufficient, the geological contacts and formation boundaries may be drawn. Through interpretation of the relationships of the older to the younger rocks, the structure of the rocks is determined in the same manner as the present structure is interpreted from areal geological maps. The extent of the ancient shorelines, overlaps, erosion, and regional warping and truncation are also readily determined. Each unconformity surface offers an opportunity for making a palaeogeological map. The greater the overlap of the overlying key formation, the more interesting and valuable is the story revealed by the palaeogeological map.

An example of a palaeogeological map is shown in Fig. 1, which shows the areal geology of the Oklahoma City oilfield immediately prior to its being covered by sands and shales of Pennsylvanian age. It is seen from the map that in pre-Pennsylvanian time formations ranging in age from Lower Ordovician to Middle Mississippian cropped out in the form of an inlier as the result of a fault with 2,000 ft. of throw. Any theory of oil and gas origin and accumulation, when applied to this pool, must be considered and timed in the light of the structure, erosion, topography, and other features revealed by the palaeogeological map as they existed at that time in the area.

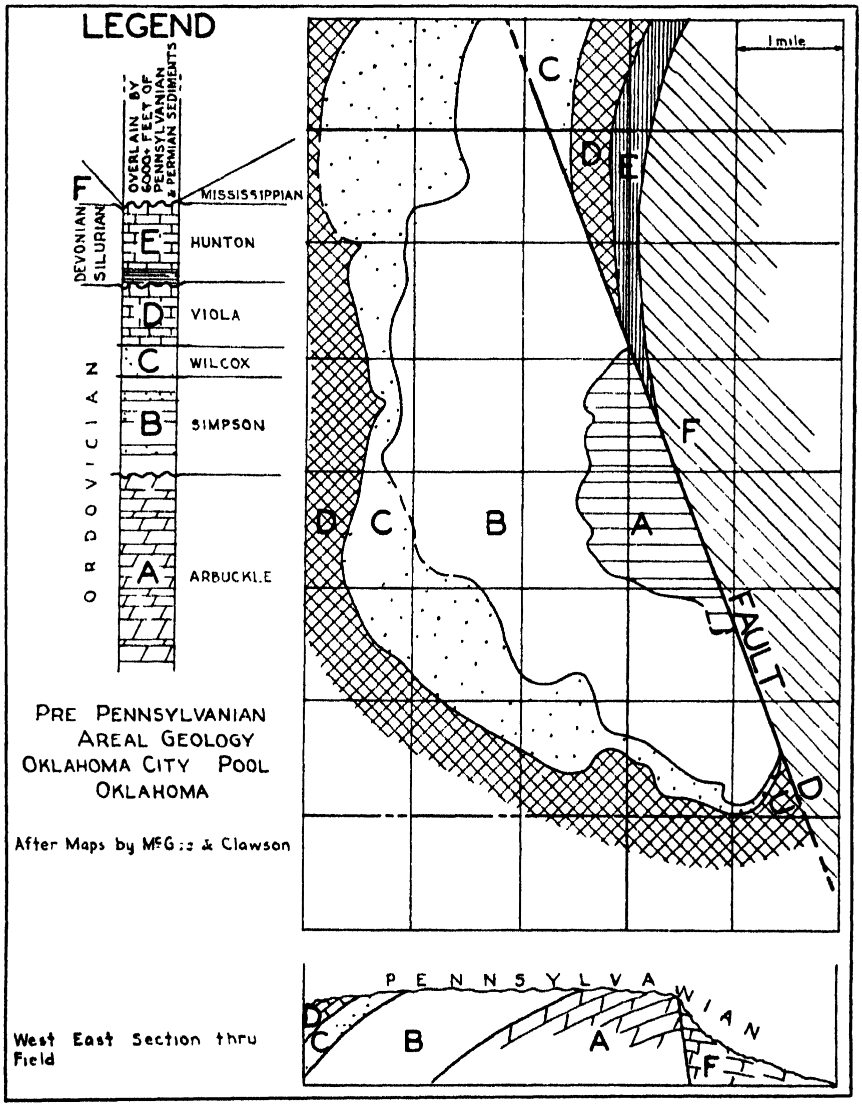

FIG. 1. A palaeogeological map of the Oklahoma City, Oklahoma, oilfield showing the areal geology as it was in pre-Pennsylvanian and post-Mississippian time. Adapted from maps by McGee, Clawson, and others.

Another type of palaeogeological map is that of a large region such as a state or a continent. An example of this sort of map is shown in Fig. 2, which is the pre-Mississippian areal geology of the United States. This map repre-

sents the areal geology of the surface upon which the Mississippian sediments were deposited. It was prepared by plotting with different symbols the age of the different rocks which are found in contact with the base of the Mississippian, and as the data accumulated and the control increased, formation boundaries were drawn with increasing accuracy. Only those points of control were used where the formation in contact with the base of the Mississippian was known, excepting where the Devonian system is now exposed, in which cases it obviously was present and not removed by erosion, prior to the overlap by the Mississippian rocks.

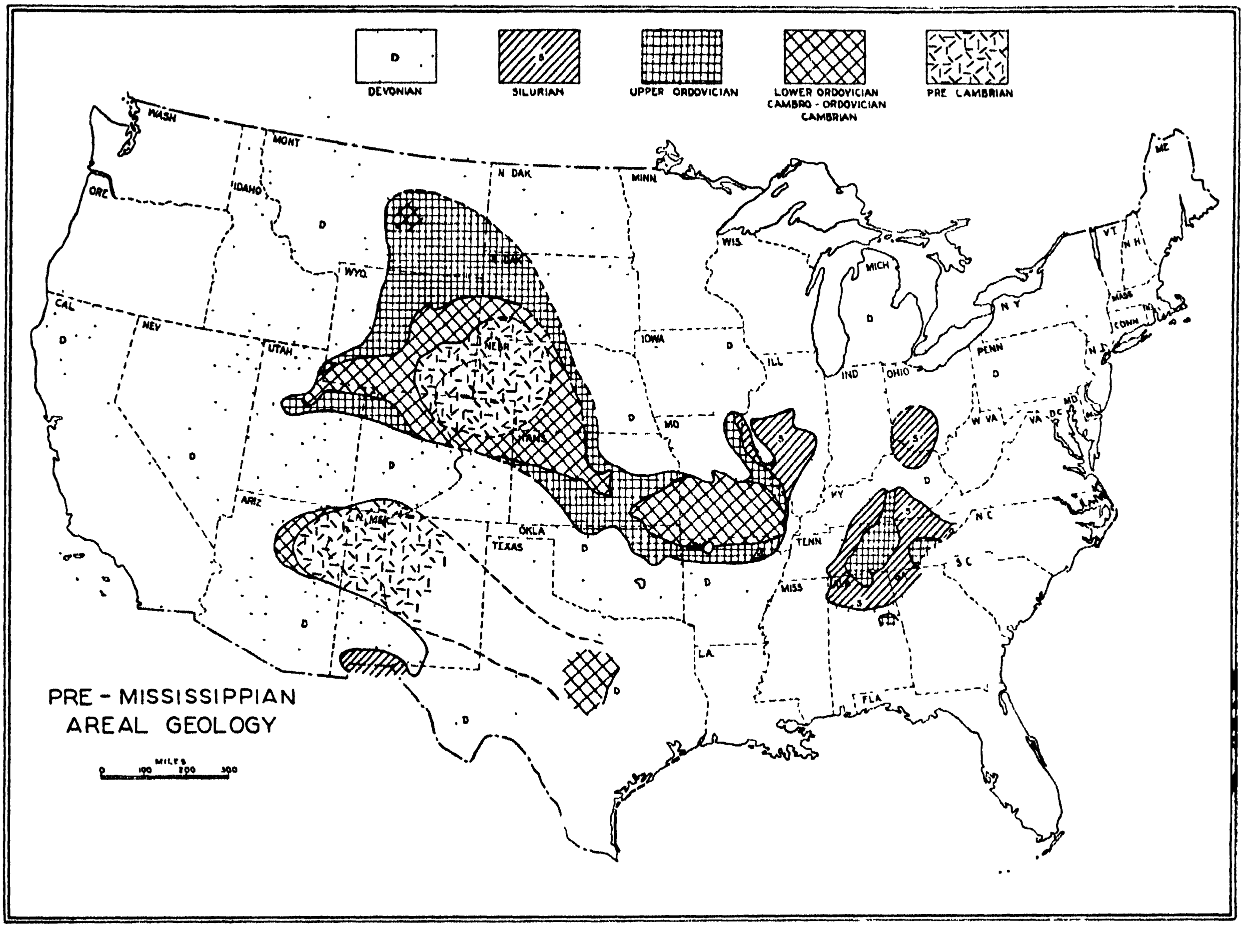

FIG. 2. Example of a regional palaeogeological map. This map shows the areal geology of the United States as it existed in pre-Mississippian and post-Upper Devonian time.

The distribution of the rocks as shown on the pre-Mississippian palaeogeological map furnishes a clue to the regional structure of the area of the United States at that time. Thus a structurally high area is shown extending from Utah and Wyoming south-eastward across the country and through the Central Kansas uplift, the Ozark uplift in Missouri, the Nashville dome in Tennessee, and opening towards the south-east beyond the present Appalachian Mountains in Tennessee. There is some evidence that a parallel high area extended from the Grand Canyon region of Arizona, across New Mexico, and at least as far as the central part of Texas. This early north-west to south-east trend of the folding possibly influenced the direction of some of the later folding such as the Amarillo–Arbuckle trend in Texas and Oklahoma. A study of the map shows the Devonian rocks also overlapping the older formations at many places, thus indicating that folding was present at least prior to Devonian time and that it persisted until overlapped completely by the Chattanooga shale and the Madison limestone of Mississippian age.

Isopachous Maps

Isopachous maps are those maps which show by means of contours the varying thickness of the material intervening between two strata or between two geological horizons. An unconformity surface is often used as one of the horizons in the preparation of an isopachous map. Such a map is of particular value when considered as a palaeogeological map, since it shows the structure of the lower of the two strata or surfaces *at the time* the upper was being formed. When used in this manner in studying an oilfield, isopachous maps furnish a method of dating and measuring the early folding and thereby the time of earliest possible accumulation of oil and gas in the fold.

Application of Palaeogeology to Accumulation of Oil and Gas

Investigations of oil- and gas-pools throughout the world have shown that the oil and water, or the gas and water, contacts tend to approach a level plane. Accumulations of oil and gas, in other words, are found to approach complete gravity adjustment to the present structure and attitude

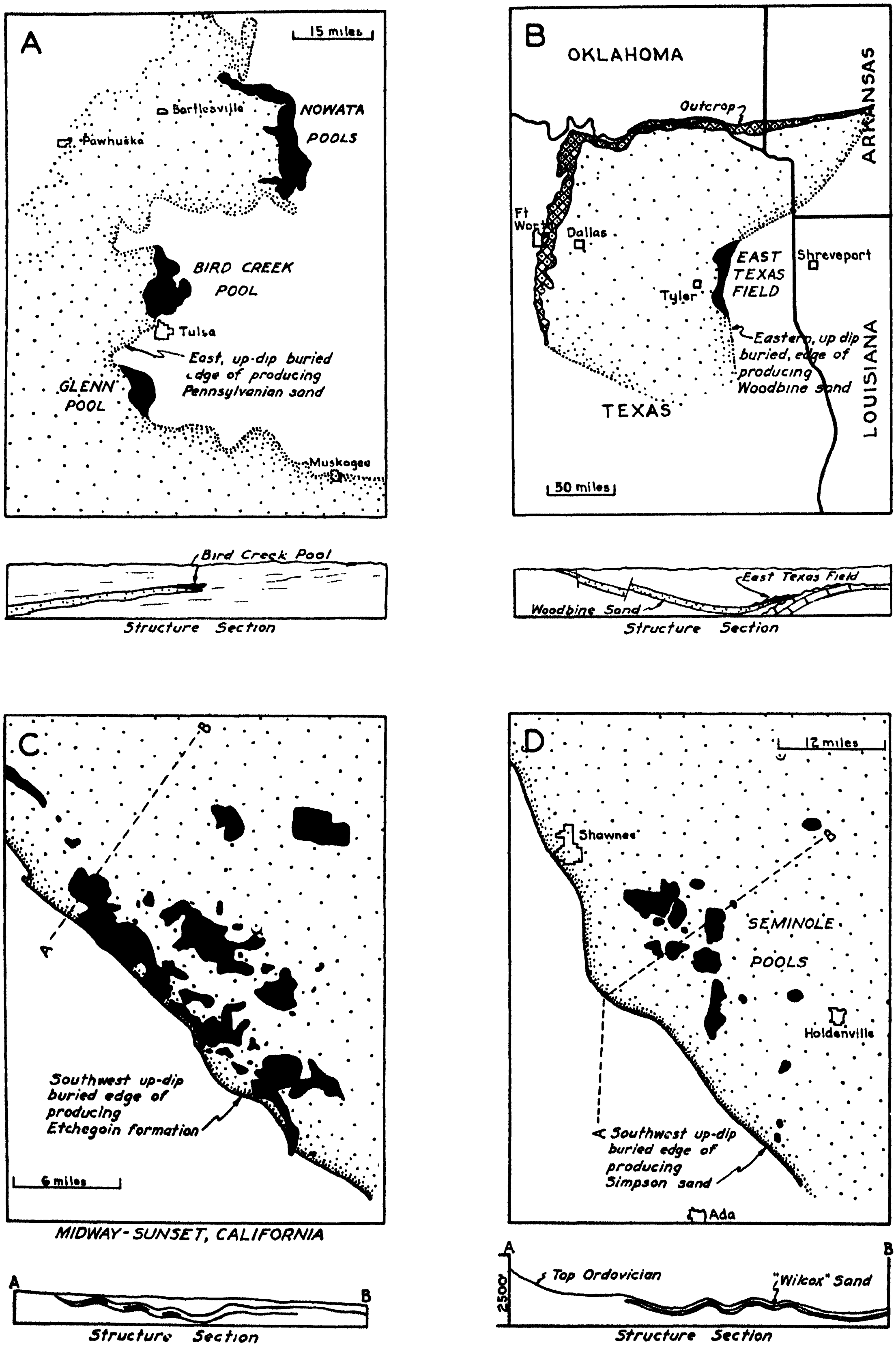

Fig. 3. Four typical examples of oil-producing areas (pools in black) which are located at or in close proximity to the edge of the producing formation. *A*, Lower Pennsylvanian sand pools in Oklahoma. (After maps by Snow.) *B*, East Texas oilfield in Texas. *C*, Midway-Sunset oilfields in California. *D*, Seminole District pools in Oklahoma.

of the reservoir rock regardless of its age or geological history. Furthermore, the oil and gas everywhere are found to occupy the highest possible position within the containing reservoir rock. As these phenomena are true of our present oil- and gas-pools, they must have been true of the oil- and gas-pools of the geological past, and a study of the changing attitude and structure of the reservoir rock, after the oil and gas have entered it, becomes of primary importance.

Furthermore, study of the palaeogeology of many oil- and gas-pools shows that the present attitude of the reservoir rock is not the same as in the past, but that it is the result of many periods of folding, tilting, uplift, erosion, and overlap of both local and regional extent. It may be assumed that the adjustment of the oil and gas to the present structure is likewise the result of a combination of repeated adjustments and migrations, each of which brought the oil and gas into gravity adjustment with the changing attitude and structure of the reservoir rock. This adjusting process commenced as soon as the oil and gas entered the reservoir rock, and must have been in progress continuously to the present time. Furthermore, it must have continued through varying environments of depth, load, pressure, temperature, water concentration, and water movement, all of which probably had a bearing on the speed and ease with which the process advanced. Stated differently, oil- and gas-pools in Ordovician rocks at the end of Ordovician time, for example, were formed and retained under the same principles of up-dip accumulation and gravity adjustment which we believe operate to-day, but the site *of these pools* was controlled by the structural conditions *of that time*. These pools were in a different structural environment during Mississippian time, again during Pennsylvanian time, and again during Mesozoic time, but gravity adjustment must have continued to operate with a consequent shifting and migration of the oil and gas into higher and higher parts of the reservoir rock as the higher areas became accessible.

Another relationship common to the majority of oil- and gas-pools is the proximity of the producing area to the edge of the producing reservoir rock. Four examples showing this relationship in widely different areas are shown in Fig. 3. The Glenn, Nowata, and similar pools in Oklahoma (*A*, Fig. 3) are at the up-dip, wedge edge of the Glenn or Bartlesville sand. The wedge edge in this case is formed by the lateral gradation of a sand into shale. The East Texas field (*B*, Fig. 3), which is the largest accumulation of oil in the world, is found at the eastern up-dip, wedged-out edge of the Woodbine sand. The edge of the sand here, however, is the result of post-Woodbine erosion. The other two examples, the Seminole district (*D*, Fig. 3) in Oklahoma and the Midway-Sunset area in California (*C*, Fig. 3), are both typical of a group of oil-pools in which the oil is found in, and related to, local anticlinal folding, but in which the group of pools as a whole is located near the edge of the producing formation. In the Seminole pools the edge is formed by the grading out into limestone and dolomite towards the south-west of the 'Seminole' or 'First Wilcox' sand, while in the Californian example the Etchegoin producing formation is truncated close to the south-western limits of production. The wedged-out edge of the producing formation is a common factor to each of these accumulations, even though the age of the rocks involved, the age and character of the folding, and the geological history are all quite different. For that reason it follows that the location of the edge of a possible producing formation is an essential element in the problem of searching for new oil- and gas-producing areas. With this relationship as a basis, a logical principle controlling the accumulation of most of our oil and gas may be formulated.

If our reasoning is correct about the repeated migration of oil and gas as they maintain gravitational harmony with the changing structure, then the observed common relationship of the producing fields in proximity with the edge of the reservoir leads to the conclusion that the earliest trap to form is very important. The earliest obstruction to the migration of oil and gas would obviously be a primary change (Fig. 3, *A*) in porosity of the reservoir rock. Regional uplift and erosion of the reservoir rock followed by the overlap of a non-porous cover would also furnish an early obstruction to the movement of oil and gas, and such a sequence has the added advantage that the wedging-out of the reservoir rock is early up the dip (Fig. 3, *B*) and therefore immediately offers a high area towards which any oil and gas in the reservoir rock would tend to move. Subsequently, local folding, tilting, and other changes (Fig. 3, *C* and *D*) may occur in the reservoir rock, with the result that as higher pore space is available to the oil and gas, they will move into it and become adjusted to the local structure by occupying the highest possible space in the reservoir rock.

STRATIGRAPHICAL CONSIDERATIONS

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STRATIGRAPHY is the branch of geological science that deals with the characters of rock strata. It includes study of the lithological nature, biological content, thickness, horizontal extent, and to some extent the structural relations of all rock layers. Determination of geological sequence or relative age, recognition of the nature and significance of lateral and vertical changes in the character of stratified sedimentary deposits, differentiation of 'natural' assemblages of rock strata of various magnitudes, and the proper classification of differentiated units are all subjects of stratigraphical inquiry.

Because the occurrence of petroleum and natural gas is associated almost exclusively with stratified rocks of sedimentary origin, the subject-matter of stratigraphy has practical bearing in many ways, directly and indirectly, on exploration for these fuels. Limitations of space prevent exhaustive consideration here of the applications of stratigraphy to scientific search for oil and gas, and accordingly we will confine attention to three aspects of the subject: (1) stratigraphical considerations of source rocks, (2) stratigraphical considerations of reservoir rocks, and (3) stratigraphical considerations bearing on the determination of geological structures.

Stratigraphical Considerations of Source Rocks

Experience has abundantly shown that certain sorts of sedimentary deposits contain no oil or gas, excepting perhaps unimportant local occurrences due to undoubtedly abnormal conditions in which the oil or gas has been derived from another source. These sedimentary deposits initially lacked the organic materials from which petroleum and natural gas might be produced. Emphatically they are not source rocks. Broadly speaking, sedimentary deposits of terrestrial origin, that is, laid down on land by agencies such as streams, winds, glaciers, or even lakes, are likely to contain little or none of the source materials of petroleum. No commercially valuable accumulations of oil or gas are to be expected in such deposits. On the other hand, plant and animal life is extraordinarily abundant in most parts of the shallow seas, and conditions here favour in varying degree the burial and preservation of hydrocarbons derived from this marine life. In view of this fact, and because known oil and gas accumulations appear associated so universally with marine formations, it is reasonable to conclude that important source rocks of oil and gas are marine.

Despite much investigation it is not yet possible to define the environmental conditions most favourable to the making of oil and gas source materials, but evidence points to certain types of marine shales as the most important type of source rocks. Accordingly, stratigraphical consideration of prospective oil and gas development should direct attention to areas that contain marine deposits in which there are appreciable thicknesses of carbonaceous or bituminous shales, and should disregard as potential oil and gas producers formations of continental origin.

Since conditions of sedimentation along the borders of a basin may differ materially from those within the basin, it may happen that absence of source rocks and of subsequent accumulations of oil and gas in one area accompanies their presence in neighbouring territory. This is the case in certain parts of the Mid-Continent and Gulf Coast fields of the United States. Knowledge of the nature and direction of stratigraphical changes guides exploration under these conditions. Lateral changes in the Permian rocks of western Texas, in part associated with the building of thick limestone reefs, exert a very important influence on the location of oil- and gas-fields in that region.

Stratigraphical Considerations of Reservoir Rocks

Reservoir rocks include any type of sediment (and exceptionally igneous rocks associated with sediments) that is moderately porous and permeable. The pore space in the rock must be quantitatively sufficient to provide effective storage for the oil or gas, and the passage-ways must be large enough to permit relatively easy movement of fluids. Loosely cemented gravel and sand deposits contain a large percentage of pore space and are very permeable. They make excellent oil and gas reservoirs. Limestones and dolomites likewise contain a large aggregate porosity if weathering, solution by circulating ground water, or certain other influences have affected them. Large quantities of oil and gas come from such reservoir rocks in some fields.

From the stratigraphical viewpoint, the occurrence of various sorts of reservoir rocks, their kind, position with reference to associated formations, approximate thickness and horizontal extent, can be determined by field investigations or by compilation of data obtained from subsurface studies. This type of stratigraphical information, in connexion with knowledge of geological structure, is most important both in the initial exploration and in the later development of an oil- or gas-containing area. Some of the types of stratigraphical relationships shown by reservoir rocks in different fields may be considered briefly.

Sandstones that in physical characters and stratigraphical relationships offer suitable reservoir sites for oil or gas accumulations include littoral and near-shore deposits of former seas, and also in some cases sand accumulations of sub-aerial origin, where these are associated closely with marine strata. The marine sandstones are likely to be sheet-like bodies of considerable uniformity that extend over large areas, but it is generally found that persistence is greater in a direction parallel to the former shore line than toward the deeper part of geosyncline, interior basin, or large seaway. In an off-shore direction the sand becomes finer and grades into shaly or calcareous deposits that may be good source rocks but lack the properties of an oil or gas reservoir. Stratigraphical studies provide a basis for inferences concerning the distribution and the direction of lateral changes in such sandstone deposits. The lenticular character of many sheet-like sandstone bodies contributes importantly to their effectiveness as oil and gas reservoirs, for the presence of enclosing impervious shale prevents escape of fluids from the sandstone. Sand lenses are formed in several different ways—beach deposits that terminate shoreward, off-shore bars, barrier beaches that lie between lagoonal deposits on one side and deeper water fine sediments on the other, deltaic sands that wedge out both seaward and landward. All of these may be buried by overlapping fine sediments of subsequently transgressing

seas. Sand-filled channels, characterized by convexity of the lower boundary of the sand body, may occur in shale or limestone. Some of the 'shoestring' sands that serve as oil and gas reservoirs in the Mid-Continent field of the United States and elsewhere are of this type. In each case consideration of stratigraphical characters is of primary importance in prospecting these sandstone reservoirs.

The occurrence in many instances of coarse detrital sediments at the base of an overlapping series of rock strata, and likewise under some conditions at the summit of an off-lapping series, provides reservoir sites for oil and gas accumulations. The sandstone and conglomerate of these deposits in different places differ in age and in relationship to associated sediments. Determination of favourable areas for oil and gas exploration must take account of these stratigraphical relationships. Local deposits of sandstone and conglomerate that in many places occur immediately above unconformities are commonly sources of oil and gas production.

The porosity of many limestones and dolomites, which fits them to serve as reservoir rocks, appears to have resulted from their exposure to surface weathering and solution by circulating ground water previous to burial by younger sedimentary deposits. The process of dolomitization may also increase porosity. It is from investigations of a stratigraphical nature that the occurrence of such conditions can be ascertained and applied to exploration of areas in which the formations concerned are buried. This is well illustrated in western Kansas and in Oklahoma, where stratigraphical research that showed the existence of certain unconformities has guided prospecting for the porous, weathered limestones below the unconformities, as well as the sandy accumulations above the unconformities.

A special type of stratigraphical relationships is furnished by deposits in which differences of facies are maintained in adjoining areas during deposition of a thick series of sedimentary deposits. Such conditions are encountered in various geosynclines where sediments of one type accumulate in one place while materials of another sort are contemporaneously laid down near by. The thick limestone reefs in the Permian of Trans-Pecos Texas and southeastern New Mexico appear to be exactly equivalent in age to thin-bedded limestones and shales, dark siliceous shales, sandstones, red beds, and evaporite deposits in closely adjacent areas. Oil and gas in large quantities are found in certain parts of this region, chiefly in massive limestone. The mode of occurrence of the oil and gas, and the apparent structural relationships of the fields are not at all intelligible unless consideration is given to the stratigraphical conditions that have been deciphered.

Exploration for oil and gas, as guided by geological studies, until now has been almost entirely dependent on finding favourable geological structures. First by surface investigations, then, in many regions where surface evidence of structure is lacking, by core-drilling, and finally by application of geophysical methods, the search for structural traps has been extended until in the more intensively studied regions of the globe, such as the possible oil-producing areas of the United States, there is little prospect of finding important new fields as a result of the discovery of untested favourable structures. On the other hand, there are large possibilities of the existence of undiscovered major oil- and gasfields in which accumulation of the oil and gas is due to stratigraphical conditions. The occurrence of a porous reservoir rock overlain by impervious strata and terminated laterally on the up-dip side by overlap, by thinning to disappearance, or by gradation into fine sediments, furnish favourable conditions for commercially valuable accumulation of oil and gas that may be exceedingly important. Such 'stratigraphic traps' are primarily due to the nature and relations of the rock strata and not to anticlinal structure. It is obvious, also, that the location of such oil- and gas-productive traps may not be discoverable by methods of structural geology. The great East Texas oilfield, the Glenn, Burbank, and Seminole fields in Oklahoma, and the Coalinga field in California are examples of accumulation of oil and gas in very large quantities mainly or entirely because of local stratigraphical conditions. It is reasonable to conclude that the chief new developments in oil- and gas-finding, as regards additions of important production, will come through application of stratigraphical studies which have as their object the finding of 'stratigraphic traps'.

Stratigraphical Considerations bearing on Determination of Geological Structure

The cardinal importance of geological structures in connexion with exploration for oil and gas is well recognized. This subject is treated at some length in another section of the present work. It is pertinent here merely to call attention to the place of stratigraphy in the determination of geological structures, both surface and subsurface, by the geologist. Without detailed knowledge of the character and sequence of rock strata in a given region it is impossible to formulate conclusions as to structure that will serve as a useful guide to oil and gas development. In actual practice the structural geologist leans heavily on the stratigrapher, or rather, he himself uses all possible stratigraphical information for determining the character, order, thickness, horizontal persistence, and correlation of the beds whose structure is to be indicated. A key horizon or datum is selected for contouring, and a variety of factors, especially precision of determining the key bed, bear on such selection. Special account must be taken of variations in thickness of certain layers, especially if these variations are abrupt, and consideration must be given to unconformities.

One of the obvious but not immediately recognized relationships of stratigraphy to geological structural work in connexion with oil exploration is that presented by variations in thickness of stratigraphical units. Few formations or groups of formations have uniform thickness within even a few square miles of areal extent. Accordingly, it is necessary in determining the structure of different rock layers to make thickness (isopach) maps which indicate the convergence in certain directions between selected datum surfaces. Studies of this sort may demonstrate that a barely perceptible structural 'nose' or terrace in surface rocks may overlie a well-defined 'closed' anticline a few hundred feet beneath the surface, and this anticline may serve as a place of accumulation for commercially valuable quantities of oil and gas.

Finally, we may note that determination of subsurface structure in most oil- and gasfields or in areas of exploration is primarily based on stratigraphical conclusions as to identity and age of rocks penetrated by the drill. The development of technique using microscopic fossils, petrographic characters, insoluble residues, analyses of waters, and all other possible means of identifying stratigraphical horizons, constitutes the greatest advance made in recent years in the application of geology to the quest for oil and gas. Reliable conclusions as to geological structures rest on these more accurate determinations of stratigraphical conditions and relationships.

PALAEONTOLOGY

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THE value of fossils to oilfield geologists consists essentially in the fact that they may serve to distinguish horizons in a rock-sequence. Two beds of sand or marl which are indistinguishable lithologically may contain quite different fossils, while the same fossil species may occur in limestone in one place and in shale in another, thus proving (or at least suggesting) that they are of the same geological date. It is to William Smith (1769–1839) that we owe the demonstration of this use of fossils. His pioneer observations were quite empirical: he had no explanation of why the fossils of the successive strata of the Bath district should differ from one another—or why an oyster should be the index fossil of one formation, an ammonite of another, and a sea-urchin of a third. Practical stratigraphical palaeontology still remains in large measure empirical; but there are traps into which empiricists may fall, and more scientific consideration is necessary to avoid them. The fossil fauna (or flora) of any bed is determined by a number of factors:

1. The actual living faunal (or floral) community which existed in the immediate area where the sediment now forming that bed was being deposited. This in turn depends upon—

   (*a*) the stage of evolution of the animal (and vegetable) world at the time;

   (*b*) the particular conditions prevailing in the immediate area of deposition, determining what forms of animal (or plant) life could and could not live there;

   (*c*) the geographical restrictions to dispersal, which isolate provinces, and, when they cease to exist, allow of sudden and rapid migration.

2. The facilities for transport of dead organisms or their skeletons to areas where they were not found living.

3. The local conditions which determine whether any or what organisms or what portions of them shall be preserved after death.

Let us consider these in order.

1. (*a*) That animal and plant fossils, viewed in a broad way, show a general progression from the earliest fossiliferous deposits to the present day, was recognized long before Darwin's theory of evolution was propounded, and by palaeontologists like Agassiz who rejected that theory.

Thanks to this generalization, even a tyro in palaeontology can recognize whether any moderately varied fossil fauna comes from strata of the Older Palaeozoic, Newer Palaeozoic, Mesozoic, or Cainozoic Era: with luck he may even be able to refer them to one of the periods into which each era is subdivided. Even here, however, empiricism creeps in. No one can say why Trilobites are confined to the Palaeozoic: they were not ancestral to any later forms. With Cephalopods the case is better, for Goniatites are obviously less highly evolved than the Ammonites which succeeded them. It is among the Vertebrates (and especially the Mammalia) that the stage of evolution can be most safely recognized and used as a time-indicator.

There are, however, a few cases in which slow- and short-range evolution may be of stratigraphical service. Such are the lineages in Lower Carboniferous corals, the gradual changes in detailed structure of the Micrasters during the deposition of the White Chalk, and probably those in certain long-range Tertiary foraminifera which oilfield palaeontologists are now following up. These are characteristic of periods and areas where external conditions remained fairly constant, or changed fairly steadily in one direction, so that evolution (far slower than the average) took place without the disturbance produced by faunal migrations. In the Roumanian and South Russian oilfields the evolution of the *Adacnidae* may be of service as a guide to age, if the difficulties due to complex branching can be eliminated; and the rapidity of evolution of *Valenciennesia* suggests it as a possible means of subdividing the Maeotian stage.

In general, as we descend from Vertebrates to Invertebrates, and from the eras and periods to the finer time-divisions, the direct applicability of grade of evolution to determination of age becomes less and less, owing to the increasing importance of other factors, namely:

(i) **Persistence of Type.** There are certain forms of life which endure for long periods with little or no change, or at least without any steady change in one continuous direction. The classical example is the brachiopod *Lingula*, ranging from Ordovician to Recent. *Nucula* (or closely allied forms, not readily distinguished by the field-geologist) ranges from Devonian to Recent (Cretaceous to Recent in the narrowest interpretation of the genus). Some Recent lamellibranch genera start in the Carboniferous, and limpets not differing apparently from the Recent *Patella* date from Silurian time. Similarly, *Nautilus* ranges from Triassic to Recent. Even among the rapidly evolving Mammalia we find the opossum (*Didelphys*) already existing in Eocene time. Descending to species, we find that certain oysters, which have been taken as horizon-markers because they 'flare up' in profusion in certain beds, did not become extinct after flaring up, so that solitary specimens are untrustworthy guides to age (e.g. *O. gryphoides* [*crassissima*], accepted as distinctively Miocene, but surviving to-day in the Bay of Bengal).

(ii) **Repetition and Convergence of Types.** Among Mollusca, the possible variety of shell-form (and ornament) is so limited that it is not surprising that the same form should be repeated at different periods. Thus some Tertiary Pectens have been mistaken for Jurassic species, and (when only shell-form is seen) *Inoceramus* may be confused with *Posidonomya*, &c. The Middle Miocene *Carditae* of the *C. jouanneti* series (*Megacardita*) reproduce the more striking features of the Eocene *planicosta* group (*Venericor*). When the shape is an adaptation to some particular environment there may be *convergence* between widely separated groups, as in the various boring bivalves (*Teredo*, *Clavagella*, &c.). In most of these cases a complete study of the shell will reveal some internal distinction between repetitive or convergent forms, but field-geologists commonly have to deal with incomplete or difficult-to-expose material.

(iii) **Deceptive Evolutionary Series.** Among Cephalopods, Hyatt, Buckman, and others have tried to establish certain principles of evolution, but they are so subject to excep-

tions that their application to novel cases is dangerous. For instance, in the Lower Lias there is a very characteristic group of Ammonites of which *Asteroceras* may be taken as the type, which is followed in time by *Oxynoticeras*, differing from it by its stream-lined shape, indicating better adaptation to swimming. In the Middle Lias we find a parallel pair, *Paltopleuroceras* (characteristic of the Cleveland and other iron-ore deposits) which resembles *Asteroceras*, and *Amaltheus* resembling *Oxynoticeras*. But if we jump to the conclusion that *Amaltheus* must follow *Paltopleuroceras* in the rock-sequence we should be quite wrong, for it precedes it.

1. (*b*) *Facies*. This term denotes all the characteristics, physical and palaeontological, which give a rock-formation its individuality, other than those that come under 1 (*a*). Thus there are only a limited number of facies, and they are repeated over and over again with time-variations. The biggest distinction in facies is between marine and terrestrial, the latter being divisible into fresh-water and subaerial. Marine facies are dependent partly on depth, partly on the lithological character of the deposit—muddy, sandy, pebbly, neritic, &c. On the present sea-bottom there live a series of *communities*, each with its own series of *stations*, the totality of the stations forming the *province* of which the totality of communities forms the *fauna*.

1. (*c*) It is a familiar fact that the native animals and plants of one continent, to-day, are very different from those of another; and the same is true of the oceans. This is only partly a matter of climate, since artificially introduced species often thrive as well as the natives. It indicates past isolation of regions or provinces, so that the floras and faunas have evolved independently. That similar provinces have existed in the past, and that at times the barriers between them have broken down and extensive migrations followed, has been amply proved. One result of this is that newly arriving genera serve as excellent dating fossils in their new habitat, but when the geologist seeks to use them in their old home he may fall into serious error. Thus Old-World palaeontologists established a simple sequence in the Orbitoids—*Orbitoides* Cretaceous, *Discocyclina* Eocene, *Lepidocyclina* Oligocene and Miocene; but this was partly an expression of isolation followed by migration, and broke down when tried in the New World. The large *Carditae* of the *planicosta* group also laid traps for geologists, when ideas gained in Europe were too hastily applied to America. These cases illustrate, not the failure of the method, but the need to replace rough generalizations by others more accurate and complex.

2. Fossil faunas rarely correspond to pure living communities: there is more or less mixture after death. The most obvious mixture is that between the swimming or floating population (*nekton* and *plankton*) of the surface waters and the crawling or fixed inhabitants (*benthos*) of the bottom. The dead bodies of the former, if they escape being eaten, or otherwise disintegrated, will sink to the bottom and mix with those of the latter. Besides this, currents will sweep dead shells away from their station and deposit them elsewhere. In dredging, to-day, dead shells are found outside the depth-limits of the living animals. This is particularly the case with easily floated shells, such as those of the chambered cephalopods. The empty shells of the pearly Nautilus are found over a much wider area of the Indo-Pacific than is inhabited by the living animal; and the little *Spirula* has an almost world-wide distribution after death, while its living habitat is only partially known but is certainly very restricted.

This tendency to a mixture of communities to form fossil 'faunules' adds to the difficulties of the palaeo-biologist in interpreting the ecology of ancient oceans, but it is of great advantage to the stratigraphical geologist by enabling him to correlate different facies of the same age by the presence in one faunule of species which, in life, belonged to some other contemporaneous faunule.

Even terrestrial and marine deposits have a better chance of being correlated if land-animals are drowned and drifting out to sea are finally buried in a marine deposit. The only known pre-Pliocene marsupial of Australasia is *Wynyardia bassiana*, an incomplete skeleton from the marine Miocene sandstone of Table Cape, Tasmania. And the first-discovered remains of Mesozoic mammals were those in the 'Stonesfield Slate', a shallow-marine Jurassic sandstone. The discovery of the three-toed horse *Merychippus* in the marine Upper Temblor formation of North Coalinga, California, made possible a correlation between the marine Tertiaries of the Pacific slope and the inland deposits of the Rocky Mountains region.

In the Ordovician and Silurian rocks of Britain and elsewhere we find two sharply contrasted facies—'graptolitic' and 'shelly'. The former consists of shales, usually black, somewhat pyritic, and rarely with other fossils than graptolites and horny brachiopods. The latter are more varied—limestones, shales, or sandstones with calcareous brachiopods, trilobites, corals, &c. So unlike are the faunas that correlation would be almost impossible, were it not for occasional interdigitation of beds of the two facies, and also the occasional drifting of graptolites into the area of the shelly facies in which their tell-tale remains may be found, giving an exact date to the shelly deposit. In the Tertiary beds of some oilfields a somewhat similar problem is presented by the foraminiferal limestone facies and the shelly facies.

3. Every one is justifiably astonished when such soft-bodied animals as jellyfish are recognizable in special deposits such as the Mount Stephen Shale (Middle Cambrian) or the Solnhofen lithographic stone (Upper Jurassic). But most persons take it for granted that marine animals with hard, calcareous or phosphatic shells should be preserved as fossils. Yet there are everywhere destructive agencies at work on the hard shells and skeletons as well as on the soft organic tissues. The ordinary bivalve and univalve mollusca are perhaps the shells which suffer least from destructive agents, since they are found (especially bivalves) in nearly all possible sediments in which any fossils occur at all. Crustacea and Fishes are much more rarely preserved. The trawl brings up from the bottom waters of the English Channel a great abundance of Fishes and many Crustacea, but the dredge brings up the sediment from the sea-floor, and in this one may hunt in vain for any trace of Crustacea or Fishes, except a few otoliths of the latter. So, among the stratified rocks, when Crustacea or Fishes do occur, it is commonly in special beds containing little or nothing else. These seem to denote the sudden destruction of complete shoals of fish, followed by rapid burial which inhibited the chemical action that usually destroys phosphatic skeletons. The famous fish-beds in the *Alveolina* limestones (Middle Eocene) of Monte Bolca are examples.

Star-fish also occur often in special beds in which they abound, just as they do to-day in the 'starfish communities' of the sea-bottom. Such a bed must denote the sudden complete destruction of a community followed by rapid burial. But can we doubt that in the long interval

between such catastrophes starfish communities flourished year after year in the same place but left no trace behind them?

Such fish-beds or starfish-beds may be of great local value in mapping, since they are easily recognized, and if they are not repeated except at long intervals no confusion is likely to arise. But they may be repeated, and a source of confusion may then arise. The graptolite *Dictyonema* occurs in great profusion at the base of the Tremadoc beds of England, Wales, and Scandinavia. It is usual to take it as fixing a definite horizon, but in North Wales (Dolgelley district) Cox and Wells have found that there are two *Dictyonema* beds, separated by about 500 ft. of flags and shales.

MICRO-PALAEONTOLOGY

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Introduction

THIS article is intended to outline methods that may be advantageously employed in micro-palaeontology as applied to petroleum geology. The principal subject of this paper is the interpretation of palaeontological results that may be of value in stratigraphical correlation. The other aspects of the subject are only briefly touched upon, reference being given to the more important relevant literature.

The great variety of forms among the Foraminifera and the question of their classification attracted the attention of distinguished men of science during the nineteenth century. Pre-eminent among the earlier investigators were Alcide d'Orbigny and H. B. Brady [18, 1917; 1, 1884].

During the last two decades J. A. Cushman and his students have made important contributions to our knowledge of the recent microfaunas and of those from the Tertiary and Cretaceous of America. In Dr. Cushman's Introduction and Dr. Galloway's Manual [8, 1933; 16, 1933] descriptions of the Foraminifera have been outlined and extensive references to the literature given. The economic palaeontologist is deeply indebted to the numerous scientific workers, since without their fundamental morphological studies the recent developments in the practical application of micropalaeontology would not have been possible.

It has long been accepted that the larger Foraminifera (Nummulites, Orbitoidae, &c.) are of value as horizon markers. That the smaller Foraminifera could be enlisted in the service of the stratigraphist was recognized as early as 1898 by F. Chapman in his studies of the Cretaceous of southern England [3]. It was, however, not until about 12 years ago that the practical value of smaller Foraminifera in petroleum geology was first generally accepted in the Tertiary sequence of the Gulf Coast U.S.A. and California. The methods now employed in the study of foraminiferal deposits are based on the investigations of the earlier workers adapted to suit the objectives of the economic palaeontologists.

Technical Preparation of Material

The preparation of foraminiferal argillaceous deposits by washing through sieves or decanting has been described in publications by Chapman [4, 1902], Cushman [8, 1933], Hecht [17, 1933], and others. The residue thereby obtained consists of Foraminifera and sand. The concentration of the Foraminifera from a sandy residue has frequently been successfully accomplished by the use of a separation funnel employing bromoform and other heavy fluids. Also in the case of the Foraminifera being filled with air, it is frequently possible to float them away from the residue employing different suitable liquids. In the case of detailed studies hand-picking is resorted to, while, in each country investigated, slides with several specimens of the different species are prepared. For a description and illustration of convenient forms of slides that may be employed for Foraminifera reference is made to papers by Nuttall [23, 1933] and Plummer [25, 1929]. In economic work it is found that it is convenient to assign each species to its genus and add a number for the species. The numbers are usually assigned consecutively in each genus, and in this form records of the occurrence of each species are kept and frequently tabulated. Later on it is always possible to continue with the study of the scientific literature and identify the known species by their specific name.

In the case of limestones containing larger Foraminifera thin sections are generally prepared in the usual manner. A method which gives details of internal structure has recently been employed by Dr. Van der Vlerk and his students, which is less well known. It consists of the following stages:

(1) Rubbing down the limestone to obtain a satisfactory flat surface, which must be rendered smooth without being actually polished. This can be done by employing the usual abrasives.
(2) Etching this surface with dilute hydrochloric acid and mounting the rock fragment in plasticine so that the surface is uppermost and horizontal.
(3) Covering this surface with amyl acetate. While the surface is still wet it is covered over with a thin layer of 'Rawlplug durofix', which is left for 5 to 6 hours until set hard.
(4) Cutting off the edges and peeling off this layer with a sharp knife. Placing the layer between two sheets of glass (ordinary slides may be employed) and sticking paper around the edge so as to hold the slides together.

The above thin layer when viewed through transmitted light gives similar structural details to those obtained by thin sections.

The Larger Foraminifera

The so-called Larger Foraminifera consist of forms with a fairly complex internal structure which has been subject to evolutionary changes. These developments enable different species to be recognized, a number of which have a restricted vertical range and are therefore valuable as time markers. The more important Larger Foraminifera are as follows:

Palaeozoic: Fusulinidae.
Cretaceous: Orbitoides ss., Orbitolina.
Tertiary: Lepidocyclina, Discocyclina, Borelis (Alveolina), Nummulites, &c.

The Fusulinidae have received the attention of specialists investigating the Palaeozoic formations of the Mid-Continent oilfields of U.S.A. A bibliography on this family has been recently published by Silvestri [27, 1933]. The Middle and Upper Cretaceous contain rich and varied faunas of Larger Foraminifera, a number of forms having a wide lateral distribution [26, 1901–2]. *Omphalocyclus macropora* is, for example, present in the Upper Cretaceous of Cuba, Europe, and India [14, 1932; 32, 1908].

In the Tertiary the Larger Foraminifera play an important role in stratigraphical correlations in oilfield areas, where Tertiary limestones are developed. Such areas are the Netherland East Indies, India, Iran, Iraq, Europe,

Mexico, and the West Indies. A great deal of valuable information on the distribution of the Larger Foraminifera and Mollusca is contained in Dr. Morley Davies' recent book on Tertiary Faunas [12, 1934].

In the East Indies the most important investigations have been made by Martin, Douvillé, and Van der Vlerk [13, 1924–5; 20, 1931]. The difficulty in distinguishing the European stratigraphical divisions has led to the introduction of a system of lettered faunal horizons. In Europe, as in India, the Nummulites in the Eocene are important in stratigraphy and have an extensive literature [see 2, 1911; 22, 1926]. The American Larger Foraminifera have in particular been studied by Vaughan, who recently contributed an interesting paper on factors influencing their distribution [30, 1924; 31, 1933]. As regards the genus Lepidocyclina there are numerous species restricted to the geographical Tertiary regions of America, Europe, and the Far East.

Smaller Foraminifera

For correlation in petroleum geology the study of the Smaller Foraminifera has been mostly confined to Cretaceous and in particular to Tertiary microfaunas. In the Cretaceous there was a marked similarity in the American and European forms, while certain genera such as Globotruncana had world-wide distribution [6, 1926; 28, 1934]. In the early Tertiary tectonic movements caused a change in configuration of the land masses and oceans, producing different areas in which development of the microfaunas proceeded more independently. The resultant present geographical distribution of animal life has been recently summarized by Davies [12, 1934].

In the Tertiary the two principal factors which produce differences in the microfaunas are age and facies. As regards age it can readily be ascertained by a study of the literature that faunal differences exist between beds of different age and of similar facies. Instances of this have been worked out in the Gulf Coast of U.S.A. and Mexico [23, 1933]. For the American faunas typical of the different horizons reference is made to the literature, in which the smaller Foraminifera of the Miocene [10, 1933], Oligocene [5, 1923], Upper Eocene [9, 1926; 15, 1933; 19, 1932], Middle Eocene [11, 1929–30], and Lower Eocene [24, 1926] are described and illustrated. The faunas distinguished from these horizons have a regional distribution, so that where present, in the Gulf Coast of U.S.A. and adjoining areas, the major stratigraphical divisions can readily be recognized by their characteristic foraminiferal species. Difficulties are, however, encountered firstly when areas widely separated from one another are investigated; secondly, where local facies conditions are variable. As a case due to the first cause may be mentioned the Miocene of California, which contains a different fauna from that of the Miocene of the Gulf Coast. This has been explained as due to there being no marine connexion between the two areas during Miocene times. The influence of facies on the microfaunas is another factor, a brief discussion of which follows.

It is generally agreed that living conditions have had as much influence on the smaller Foraminifera as on other marine organisms, such as Mollusca. It is known from studies of living foraminiferal faunas that certain genera are commonly found in brackish water, others in a shallow sea, and others under deeper marine conditions. Furthermore there are several pelagic genera of Foraminifera which may be carried by marine currents, while the greater number of Foraminifera are bottom living. An interesting instance of the influence of depth and temperature on Foraminifera living off the coast of California has formed the subject of a recent paper by Natland [21, 1933].

In view of these facies influences it is necessary for the application of micro-palaeontology to stratigraphical correlation to proceed very cautiously before making detailed long-distance correlations in beds of approximately the same age. As a result of local facies and palaeogeographical influences Tertiary faunas closely resembling one another may occur in different areas at somewhat different stratigraphical horizons within the Tertiary.

For these reasons it is considered necessary to determine the vertical range of the Foraminifera independently in each basin of deposition. After this has been done for a particular part of a certain basin the results are applied over a larger area within the same basin. As the edge of the basin is approached local facies conditions will bring about differences in the microfauna and the vertical range of certain species. In this case it will be necessary to proceed with further detailed studies of stratigraphical sections in the areas of near-shore deposition. After this has been completed the two may be palaeontologically correlated.

It should be borne in mind that locally a change of living conditions influencing the microfaunas may be sharply defined at a given correlative stratigraphical horizon. For example, in a given area at a certain horizon there may be a clear break between marine and non-marine conditions. Similarly in a single basin at a given stratigraphical horizon there may be a sudden incursion or extinction of certain foraminiferal species. A faunal break of this type may be of great practical value for local correlation and may even be found to extend throughout the greater part of a single basin of deposition.

The submarine topography has also frequently had a pronounced influence on the microfaunas. In certain areas it has been found that overlying contemporaneous uplifts reef limestones or shallow water faunas predominate, while in the adjoining depressions marine microfaunas with different assemblages are present.

In general it may be stated that no reliable micro-palaeontological correlation can be expected unless the stratigraphical and palaeontological data are critically compared and as a basis for correlation systematically sampled sections are investigated in detail. These sections should have samples collected from close and regular intervals, so as to give as nearly a continuous stratigraphical sequence as possible. The samples, may be derived from cores in a well or from the surface and in each case should be from an area which is as far as possible not structurally complicated. Only after a basis for correlation for a particular area has been worked out will it be possible for the palaeontologist to determine the stratigraphical horizon of scattered material.

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THE CORRELATION OF SEDIMENTS BY MINERAL CRITERIA

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THE value of detrital key-minerals as clues to the source of the sediments containing them was first recognized by Thoulet [16, 1907], who succeeded in tracing to their sources in terrestrial rocks certain detrital species he had observed in oceanic deposits. He thus established a principle which has since been extensively applied to the genetic study of sedimentary rocks [2, 1933; 8, 1921; 12, 1929; 17, 1932]. But the extent to which minerals—in default of fossils or other decisive criteria, may be used to correlate one stratigraphical horizon with another is a question on which opinion is divided.

The value of mineral *assemblages* as clues to both geological age and stratigraphical horizon was first demonstrated by Boswell [1, 1916], working on a restricted area—the London Basin. The application of the method to oilfield stratigraphy, and in particular to the difficult problem of correlating unfossiliferous horizons encountered in borings, dates from 1916, when Illing [9] found that successive groups of Trinidad sediments—particularly the oil-bearing horizons—were characterized by exclusive, and therefore distinctive, mineral assemblages, which could be used as aids to correlation. Thus a principle which, in the first instance, was of purely academic interest, was brought to bear on oilfield economics.

It is therefore not surprising that the most substantial contributions to literature on this subject must be credited to oilfield geologists, whose extensive exploration of its possibilities renders their opinion on its practical value authoritative. Nor is it surprising that this authoritative opinion is divided: the situation is not unfamiliar.

In the following review of the principle and its applications a critical survey of the material evidence usually brought to bear on problems of correlation may serve to suggest possible reasons for its apparent inadequacy in particular cases.

The correlation of strata by either fossils or minerals is, of course, quite compatible with marked contrasts in both facies and mass mineralogy. Fossil and mineral criteria alike usually rest in some small fraction of a rock-mass. The fraction searched for mineralogical evidence is usually the 'sand' grade—particularly the small crop of 'heavy' minerals separable from a much larger amount of associated 'light' minerals (quartz, feldspar, &c.) by mechanical means, mainly sink-and-float technique using heavy liquids such as bromoform. The sand grade itself must first be separated from the silt and clay grades; these being mineralogically 'obscure' and somewhat unmanageable in heavy liquids unless centrifuged are usually discarded after a cursory examination of their characters. A 'limestone' facies is also liable to be discounted as a potential source of material evidence.

The small crop of 'heavy' minerals—commonly representing much less than 1% of a rock mass—is then studied as an 'assemblage': its features are compared, qualitatively and quantitatively, with those of other 'assemblages', the quest being for correspondences distinctive enough to correlate one assemblage with another. The extent to which correlation demands concordance in mineralogical (and other) details must be indefinable; but the 'probabilities in favour' increase with the number of coincidences. That stipulation on this point should possess some degree of elasticity is to be inferred from the fact that 'change'—gradual but incessant—is the feature of

(*a*) The distributive province from which a sediment derives its detrital material.

(*b*) The determinants of facies—climate, physiography, and the conditions of transport and accumulation of detrital material; progressive sorting, and the selective elimination of particular minerals by both mechanical and chemical processes.

(*c*) The post-deposition history of species actually sedimented but thereafter exposed to variable physicochemical conditions.

The various parts of a sediment are as unlikely to be initially isochemical as they are to persist under isophysical conditions.

Correlation is compatible with considerable discrepancy in mineralogical detail—provided the evidence furnished by each sediment concerned in the case reveals *certain qualities* which are both common to and distinctive of them all. This view may appear to need some defence—for which the following considerations may suffice:

(*a*) Incessant change in the determinants of facies, which may vary from one layer to another, is reflected in the variable relative stability of detrital minerals under the physicochemical conditions proper to each facies. A mineral may resist destructive change in one layer, while in another the same mineral may be partly or completely destabilized—to some chloritic, micaceous, or clayey residuum destined for laboratory discard. The resistivity of most rock-forming minerals to hydrolysis and chemical change is in inverse relation to grade size, which is a facies feature [4, 1937; 6, 1937].

(*b*) Clayey residuals are the main loci of base-exchange, which attains a maximum in clays of the bentonitic type [11, 1931, 1935]. Hence geochemical conditions at a clay-rich locus are liable to be alternately favourable and unfavourable to the stability of particular detrital species. Oscillatory conditions of this character could account for some minor discordances between mineral assemblages which, in other respects, may be essentially equivalent.

(*c*) Concretionary growths, notably the flinty and calcareous types, are liable to enclose, and preserve, minerals eliminated from matrix unaffected by these growths.

(*d*) Highly calcareous matrical matter, argillaceous limestones, and common limestones may ensure the persistence of even such reputedly unstable species as biotite, cordierite, amphibole, and feldspars. In limestones, albite may actually grow—as an authigenic species—and is commonly associated with minute well-developed prisms of authigenic quartz. Authigenic potash-feldspar is recorded from sandstones, marl, and dolomitic limestone [14, 1929]. Authigenic rutile, brookite, anatase, sphene, pyrite, epidote, &c., are as familiar, and accepted, as authigenic quartz, feldspar, calcite, siderite, dolomite, ankerite, gibbsite, sericite, chlorite, barytes, gypsum, glauconite, &c.; and the list of authigenic species grows apace: it now includes even tourmaline,

garnet, and staurolite—which figure with such monotonous regularity among species presumed to be exclusively 'detrital'.

The fact to be noted here is that laboratory routine may trap both authigenic and detrital grains of a particular species but fail to discriminate between the two categories. Moreover, conditions in one layer of a sediment may be favourable to only one category; or they may be hostile to both—in which case, an item of detrital evidence is liable to be obscured or even obliterated; in some other layer the same kind of evidence may be preserved, or even reinforced.

It is helpful to realize that the micaceous, chloritic, and clayey fraction of a sediment is likely to be in some measure authigenic—in the special sense that it may include the residuum or relics of antecedent species which, had they survived, would have ranked as material evidence. The extent to which such relics may betray their ancestry and can be figuratively 'reconstructed' or integrated to vanished species is a genetic problem with its analogues in the fields of igneous and metamorphic geology, where genetic evidence is habitually sought in relics of antecedent species [3, 1936].

The obscurity which still characterizes the silt and clay grades in sedimentary rocks is scarcely an excuse for discounting their significance as potential sources of supplementary evidence. Such material invites more serious study—by every means available.

The difficulties opposed to the fractionation and identification of clays, &c., have been considerably reduced in recent years [10, 1935]; but the additions to our knowledge concerning the specific character of clays, &c., in bedded sediments accumulate only slowly. Comparatively little is known concerning the 'heavy' minerals present in either clays or shales. Hence, serious attempts to co-ordinate arenaceous facies with silt and clay layers alternating with them have yet to be made. These attempts are not only warranted by the expectations based on them: they are actually encouraged by modern refinements of technique [10, 1935] and the abundance of diagnostic data available. The character of supplementary evidence to be gleaned from clays is outlined in the following sections:

(*a*) The solid relics of mineral change commonly include a high proportion of the layer-lattice species—chlorites, micas, and clays [5, 1937; 13, 1930]. As these relics often occupy the sites of change, their identities and habits—co-ordinated with syngenetic by-products such as rutile, limonite, epidote, calcite, silica, &c.—may contain hints which can be profitably followed up. Rutile-needles enmeshed by residual chlorite, white mica, or a clay species are familiar examples of 'residuals in place', but attempts to integrate them to some particular original species are infrequent. The interpretation of any particular occurrence—even when several residual species are still aggregated on the site of a mineral change—makes considerable demands on the researcher's background of knowledge: he sees only *some* of the terms belonging to the right-hand side of an equation of change; the problem of integrating these terms, without the aid of positive knowledge concerning the agents of change, can be as exacting as the integration of terms involved in an igneous or a metamorphic process [3, 1936].

(*b*) Clay-body is prone to 'trap' the more inert oxides such as titania, vanadia, ceria, and the oxides of manganese. Base-exchange capacity is variable, and its effects are usually occult, though they may 'seal' or 'dilate' a texture to a degree which may prevent, or promote, the migration of water, brine, gas, or petroleum [15, 1930]. Solutes such as phosphoric and boric acids may be incorporated in peculiar varieties of apatite; in ceria-rich and vanadia-rich pellets, streaks, and films, and in extremely minute pale-green prisms of authigenic tourmaline.

The interpretation of clays occurring in sedimentary rocks is seriously embarrassed by the dearth of information concerning the particular clay species likely to result from the break-down of any specified mineral (pyroxene, amphibole, feldspar, &c.) under particular conditions. In general, conditions themselves are perplexing: feldspars in granites are 'kaolinized' under conditions which are still in dispute; whereas a soda-granite related to the Dartmoor granite (locally kaolinized) carries montmorillonite—associated with topaz and petalite; both montmorillonite and beidellite characterize the bentonite clays evolved from trachy-andesitic and allied volcanic ash, &c., and these bentonitic types are more abundant than kaolin in surface soils.

It is to be admitted that in routine practice we do not always discriminate between kaolin and other clay species. Our 'kaolin' is liable to be a speciously precise label for any claylike mineral, particularly if present in only minor amount. To what extent field conditions admit of more exact determinative work on such material is an open question.

Equally doubtful determinations include a group which may be classed as the '-ic' type—leucoxenic, glauconitic, epidotic, chloritic, phosphatic, lateritic, bauxitic, &c. They can shelve so many difficulties that their value may be negligible. Many such uncertainties could be resolved by microchemical tests imposing little labour.

Treatment of varietalism is also liable to be superficial and indecisive. Garnet varieties, for example, are commonly dismissed as reddish, pink, colourless, &c., though colour, even if discernible in the smaller grains, is not diagnostic even of species; whereas density or refractive index may be, and the blow-pipe, or appropriate microchemical tests, may narrow down the species to some genetically significant variety. Other minerals, particularly pyroxenes, amphiboles, and basic micas, will afford more profitable studies when their varieties have been better characterized. Varietalism in zircon, rutile, tourmaline, staurolite, and sphene, though imperfectly understood, is usually well exploited. Some varieties of fluorite, monazite, zircon, allanite, aragonite &c., and even earthy matter associated with bitumen, display a characteristic fluorescence when exposed to ultra-violet rays. The irradiation of mineral assemblages can serve the useful purpose of directing attention to reactive species present in only minor amounts.

The considerations outlined above may serve to show that the mineralogical evidence usually brought to bear on correlation problems is at best partial, and frequently qualified by uncertainties. Unless reinforced by numerous and striking coincidences, distinctive key-minerals, and skilful handling of detail, it can but be equivocal. The degree of security afforded by such evidence may be relatively high in the case of the geologically 'younger' sediments in which variable frequency 'rings the changes' on a large number of species, and endows assemblages with variety. Here, statistical treatment comes into its own [e.g. 7, 1933]. Every identification established is an additional item of evidence, and an added security.

It is sometimes said that, for correlation work, it is less important to identify an unfamiliar mineral—particularly if it is scanty or rare, than to satisfy oneself that the

mineral is the same as another, which may be dubbed 'mineral X' without prejudice to the problem at issue. Such a doctrine is indefensible: to presume that the specific identity of an unfamiliar mineral is of no consequence is taking too narrow a view of the problem. No competent worker would ignore the genetic significance of numerous 'uncommon' minerals liable to spice assemblages of the commoner and more familiar minerals; nor would he restrict his examination to assemblages of 'heavy' minerals.

The task of correlating sedimentary rocks, or even of interpreting a single horizon, is liable to be underrated. It is a problem in genetics [2, 1933; 8, 1921; 12, 1929; 17, 1932], and requires a knowledge of both mineralogy and petrology to at least the standard exacted by corresponding problems in the fields of igneous and metamorphic geology.

All things considered, it would not be captious to suggest that, where the whole of the evidence assembled appears to be inadequate for the purposes of a correlation, the inadequate feature of the case may lie in the quality of the examination applied to it.

Reverting to the restricted range of 'heavy' minerals which may be described as 'common' in the older geological formations, two observational facts can be co-ordinated:

1. Mineral assemblages tend to be simplified with progressive sorting and reduction in grade size—processes which converge towards the segregation of silts and clays.
2. Further simplification occurs with the passage of geological time.

Thus facies of sediments, and geological age, are among the primary factors which determine the mineral assemblages we actually examine. The relative stability of minerals—like the 'order of crystallization' of magmatic minerals—is a theme beset with apparently conflicting observations and opinions. Contrariety in the 'relative' behaviour of some particular species (e.g. biotite) serves the useful purpose of stressing the complexity of factors concerned in the growth, the transformation, and the destruction of mineral species [3, 1936].

Much of the experimental work hitherto done on the relative stability of the common rock-forming minerals has presumed that, under natural conditions, the action of water as a destructive agent must be reinforced by solutes—among which have figured carbonic-acid gas, various mineral acids, humic extracts, &c. These in turn are reinforced by such pressures, and temperatures, as short-period experiments appeared to justify.

But cold water alone is found to be highly reactive towards dust-fine particles of most of the common rock-forming minerals [4, 1937; 6, 1937]: by aqueous extraction of their bases, accompanied by hydration, they are degraded towards layer-lattice end-products belonging to the sericite, chlorite, and clay-types.

The alkalinity imparted, instantly, to cold water by powdered glass is a commonplace fact—readily demonstrated by using water containing an indicator such as phenolphthalein. But a similar reaction, variable as regards intensity, is given by finely divided biotite, and other basic micas; amphiboles and pyroxenes; olivine, apatite, and sphene, and some varieties of tourmaline and garnet; chlorites, epidote, zoisite, calcite, and allied carbonates, and all feldspars and feldspathoids, &c.

Sericite, hydromuscovite, and true muscovite are among the less readily reactive species; but their reactivity increases in proportion to the fineness of their powders. Even these resistant species, in common with the basic micas, yield up an appreciable proportion of their bases (including alumina) on treatment with saline solutions such as brine [4, 1937].

The extent to which hydrolysis appears to depend on both grade size and the solutes present in the water suggests a possible explanation of the apparent scantiness of 'heavy' detrital species in such clays as have been examined. In some measure it must also determine the extent to which *original* mineral composition, and the character of parental rock-sources, can be safely inferred from the mineral assemblages isolated from any particular facies of sediment.

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SECTION 8

GEOPHYSICAL METHODS OF EXPLORATION

GEOPHYSICAL METHODS

INTRODUCTION

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THE applications of physics to the finding of oil have become so numerous and varied that a large volume would scarcely suffice to cover the subject. Under these circumstances it seemed wise to select writers, with sound theoretical knowledge and practical experience in the field, who would set forth the general aspects of the chief branches of the subject. Those who actually work in the field soon find that the principles of physics hold out of doors just as they do in the laboratory. The scale of the work changes, but not its character. There is, however, this marked difference. In the laboratory the experimenter works with selected materials, either elements or preparations which are homogeneous and of a known standard of purity. In the field the geophysicist must take things as they occur, and he rarely meets with a homogeneous material. For example, the electrical conductivity of rocks depends partly on the nature of the material, but more largely on the amount of water content and on the nature of the salts which are in solution. All these factors vary from point to point, and nature never repeats itself!

Except under unusually simple conditions a magnetic survey can throw little light upon geological structure, and yet there are cases where a magnetic dike or ore-body, or a larger mass with marked magnetic properties, can be readily traced or clearly defined though far underground. Two methods of comparatively recent introduction have made very rapid progress.

(i) The account of electrical coring, as given by the late C. Schlumberger, indicates how, by the use of electrodes on cables lowered inside an uncased drill-hole, it is possible to obtain striking indications of the successive layers underground which even drill-cores might fail to reveal.

(ii) An artificial blast, due to high explosives near the earth's surface, will give rise to seismic or shock waves which are reflected back from successive layers or discontinuities, and produce records with the help of electrical seismometers or other earthquake recorders. This method has had wide applications in finding the depths of successive layers and in working out the underground structure of oil-fields. The electrical seismograph detects vertical motion by the movements of a wire or small coil suspended in the magnetic field of a magnet or electromagnet resting firmly on the ground. The shock causes a relative motion of the wire across the field, and a current is thereby induced which, possibly amplified, causes a deflexion in some type of galvanometer, and this in turn moves a beam of light affecting the running film of a camera. It is noteworthy that a good *vertical* seismograph is not too greatly affected by the *horizontal* waves which come rolling along the surface of the earth from the shot-point not far away. The same instrument is highly sensitive to the waves which have gone down a much larger distance to some reflecting layer and echoed up again almost vertically to the recorder. Moreover, it is possible to tune the oscillator to the reflected longitudinal compressional waves and, during amplification, to filter out the undesired transverse surface waves which have a different periodicity. The technical skill and high accuracy of the records both in seismic and torsion-balance methods are well matched with the intelligent interpretations of the geophysicists. Those who wish to pursue the matter further may consult the recognized text-books or read the geophysical papers published by the American Institute of Mining and Metallurgy and by other societies. In the south of the United States there are vast regions of a fairly uniform type, and approximately horizontal, wherein massive domes of rock-salt have been thrust up from below and yet have their caps hundreds or thousands of feet beneath the surface of the earth. Oil and sulphur deposits are frequently associated with the upper surfaces of such domes, so that a most active search for them has been made successfully, and it still continues. The rock-salt has a low density and a high elasticity as compared with the surrounding strata, and on both counts the shock waves have a higher speed in the rock-salt. In the refraction method the detectors may be arranged in a straight line or spread out in a fan shape. A shot fired from a point at a known distance affects a number of these electrical seismometers, and calculations reveal whether or no there is a salt-dome beneath any of the lines of fire. Discovery, if made, is followed by further work with torsion balance or seismometer in order to obtain the precise position, shape, and depth of the dome, after which in due course drilling occurs under advantageous circumstances with a minimum of cost. Moreover, the best place in which to store oil is where it occurs underground, until it is needed, and a large company prefers to obtain control of a whole salt-dome rather than to pump oil feverishly against an adjacent rival company.

The following seven articles are arranged in the usual order—without suggestion of any order of merit—magnetic, electrical, gravitational, and seismic. The authors belong to various nations and have worked in various countries, and omissions have not been intentional.

The titles of the articles and the names of the authors are as follows:

Petroleum Geophysics. DONALD C. BARTON, Ph.D., M.Inst.P.T., Geophysicist, Humble Oil and Refining Company.

Magnetic Methods. W. P. JENNY, Geophysicist.

Electrical Prospecting for Oil. C. SCHLUMBERGER, M.Inst.P.T.

Electrical Coring. C. SCHLUMBERGER.

Gravitational Methods of Prospecting. DONALD C. BARTON.

The Refraction Method of Seismic Prospecting. J. H. JONES, Ph.D., D.Sc., Chief Geophysicist, Anglo-Iranian Oil Company.

The Reflection Method of Exploring Subsurface Geology. BURTON MCCOLLUM, B.Sc., A.A.A.S., Geophysicist.

In the first article of this series on Geophysics Dr. Barton draws on his extensive practical experience in the

field and gives a summary of the main methods available to geologists and prospectors for oil. He takes his examples from the southern regions of the United States where success has been well achieved, perhaps owing to a certain simplicity of structure, lending itself particularly to the two methods—torsion balance and seismic.

Dr. W. P. Jenny, writing on 'Magnetic Methods', advocates the subtraction of regional from total magnetic vectors so as to obtain the residual vectors which are due to the local distribution of magnetic material underground. His method of plotting such vectors, so as to show the residual horizontal and vertical components in direction and magnitude, is worthy of careful study. There are regions where the magnetic method is useless, because of an unequal distribution of magnetic material in rocks of similar geological age and structure. There are other regions where the magnetic method, altogether apart from the search for iron, nickel, and cobalt deposits, may be of great assistance in tracing the extension of known massive beds far underground, as has been successfully done in Germany and South Africa.

One of the pioneers of Electrical Prospecting, C. Schlumberger, has died since he wrote his two articles. In prospecting for oil electrically it is essential to use an indirect method and to search for oil-bearing strata by detecting differences in their relative conductivity. For this purpose direct or alternating current is passed through the earth between two well-separated electrodes connected to a generator. The potential difference between another suitably placed pair of electrodes is measured by a potentiometer, and a calculation leads to a knowledge of the *average* resistivity of a large block of underground material. A note on this method is added at the end of this introduction. The nature of the rock may be inferred because different strata have a wide range of conductivity—the reciprocal of resistivity. It is hopeless to attempt a direct search for oil by electrical means which are at best but an aid to the geological interpretation. On the whole it may fairly be said that at present both magnetic and electrical methods hold a secondary place as compared with gravitational and seismic methods, at least so far as oil-prospecting is concerned.

On the other hand, Schlumberger rightly insists upon the importance of the recent developments of 'Electrical Coring'. Spontaneous polarization can be detected and measured between two electrodes (non-polarizable) placed on the surface of the earth and connected to a potentiometer. It is rare to find two points which are at the same potential, such points indeed lie on equipotential lines which can be plotted on a map. This method was first used with success in the search for such minerals as are chemically affected by the action of underground water, for detectable effects often reach the surface of the earth.

When drilling for oil it is sometimes possible to extract and examine cores at successive depths, but these samples are necessarily small in diameter. It is, however, also possible to lower a cable with a wire leading to a suitable electrode in the drill-hole while the upper end is connected to a potentiometer, the other side of which is joined to a fixed electrode on the earth. As the cable is lowered in an uncased drill-hole the potential at successive heights is indicated and recorded by the potentiometer with camera and film. This natural- or self-potential is mainly due to the water and dissolved salts in the cavities of the surrounding strata, which have various degress of 'permeability'—a word which must not be confused with magnetic permeability, for it indicates the extent to which water penetrates a material. The permeability to water varies greatly for such materials as sand and clay. Moreover, an oil sand behaves very differently from a sand containing water. This may be seen in the diagram which Schlumberger gives of actual records. This, however, is but half the story. The resistivity method may also be used in an uncased drill-hole. A cable with three electrodes not far apart is lowered gradually into the hole. A fourth electrode is earthed near the operator. It is to be understood that this electrode and the lowest one in the drill-hole are current electrodes, excited by a generator. The remaining two electrodes are potential electrodes, connected to a recording potentiometer. By this means it is possible to measure and to record the resistivity of the rocks in the neighbourhood of any part of the boring. The two methods, self-potential and resistivity, need but one cable, and both records may be made at the same time as the cable is raised or lowered. The joint readings enable distinctions to be made between different strata, which in some cases a single record might fail to do. The actual detection of oil is possible, and the difference between oil sands and water sands, between water and oil, between clay and sand, &c., are well marked. The best evidence in favour of this scheme is the rapidity with which its use is spreading.

The next article on 'Gravitational Methods of Prospecting' is also by D. C. Barton, and it deals with the use of the torsion balance with which he has had much experience and success. There has been steady improvement in the instruments, technique, and calculations since the pioneer days when Eötvös used a torsion wire to suspend a light horizontal beam with equal weights at each end, placed, however, at unequal heights. The precise location of salt-domes, far underground, in Texas and Louisiana stands out as one of the greatest achievements in applied geophysics.

Seismic prospecting is presented under two headings. The first method to be widely adopted was 'The Refractive Method of Seismic Prospecting', here described by J. H. Jones of the Anglo-Iranian Oil Company. This scheme has led to the discovery of many salt-domes, in such regions as they occur, particularly north of the Gulf of Mexico. The times of travel from shot-point to a number of recording seismometers, at measured distances, reveal the presence of salt-domes by a detectable increase of speed.

In the last article is a description of the 'Reflection Method of Exploring Subsurface Geology' by Burton McCollum. This method at first met with indifferent success, but various improvements in the instruments and their use have led to great developments. The depths of reflecting discontinuities in strata can be accurately determined, and the dip of such layers may be ascertained. A comparison of records in two analogous localities may be made, and an unknown, undrilled place may be interpreted in terms of a well-drilled and successful oilfield. The actual seismometer record is published (p. 391) and deserves a careful study.

In fact, geophysics, wisely applied, may give valuable information perforce concealed from a geologist and only partly revealed by the more expensive method of drilling. The means employed must be adapted to the existing circumstances, as when speed-boats are used to explore seismically the bayous or lagoons along the coast of Louisiana. The best possible instruments must be used, and these require capable men both to operate them and to calculate and interpret the results. Great frankness is also

essential, so that geophysicists may be ready at all times to state to what extent methods may be helpful, the nature of the difficulties to be overcome, and under what conditions failure may be expected.

The following text-books may be of service:

Elements of Geophysics, by RICHARD AMBRONN, translated by MARGARET C. COBB, pp. xi, 372. (McGraw-Hill, New York, 1928.)

The Principles and Practice of Geophysical Prospecting, by A. B. BROUGHTON EDGE and T. H. LABY (1931).

Applied Geophysics in the Search for Minerals, by A. S. EVE and D. A. KEYS, pp. x, 296, 2nd edition. (University Press: Cambridge, 1933).

A NOTE ON THE MEASUREMENT OF GROUND RESISTIVITY.

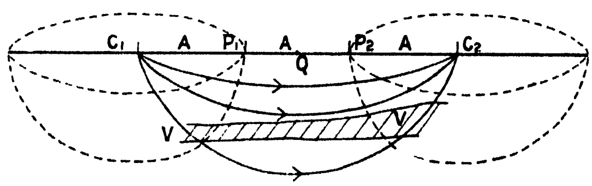
It is possible to determine the average resistivity of the ground by means of four electrodes placed in a straight line on the surface of the earth and making good contact with it. Two electrodes C_1, C_2 are current electrodes and they are connected either with a generator or a battery, for it is possible to use either alternating or direct current. The other two P_1, P_2 are potential electrodes connected by well-insulated wires to a suitable potentiometer. It is convenient to make the three intervals between the four electrodes each equal to any desired length A. The theory of this method was first given by Wenner in 1916. If ρ is the uniform resistivity of the ground; I the total current flowing in the ground between the electrodes C_1 and C_2; V the difference of potential between P_1 and P_2; then for any selected value of the intervals A, it can be proved that, for homogeneous ground,

$$\rho = \frac{2\pi AI}{V}.$$

An ingenious proof by L. V. King is given in *Applied Geophysics*, by Eve and Keys, p. 274, 2nd edition (C.U.P., 1933).

The principle of this method is illustrated in the next column, where the lines with arrows indicate the current in the ground spreading outwards between C_1 and C_2. The bowl-shaped figures, outlined by dots, surrounding C_1 and C_2 are a pair of equipotential surfaces through P_1 and P_2, and it is the *average* resistivity of the ground between them that is determined. The equipotential surfaces are not spherical nor are C_1 and C_2 their centres. The current lines cut the 'bowls' at right angles.

If VV represents a good conductor, either a metallic ore-body or a layer of salt-water, then the average resistivity of the region will be much less than if no such body were present. Hence by traversing an area with the four electrodes, keeping the electrode intervals A constant, the scheme becomes a detector of underground conductors. It may thus find salt pools, and theoretically it might detect the presence of bad conductors, such as oil, but actually the amount present is insufficient for detection at depth.



It is also possible to remain at one place such as Q, and to increase the value of A, so as to search more deeply in the ground for lower conducting bodies. Another plan is to place one electrode C_2 a long way (say, 1,000 yards) from C_1, and to measure the potential difference V between P_2 and P_1, when at distances a and b from C_1. In this case the average resistivity is given by

$$\rho = \frac{2\pi ab}{a-b}\frac{V}{I}.$$

By such means it is possible to explore for conducting bodies in the region round and below C_1. This method is closely allied to electrical coring in uncased drill-holes.

PETROLEUM GEOPHYSICS

By DONALD C. BARTON, Ph.D., M.Inst.P.T.
Geologist and Geophysicist, Humble Oil and Refining Co.

INTRODUCTION

THE geophysical methods of prospecting are the most recently developed schemes which the petroleum geologist has available for use in the oil prospector's search for petroleum. Geophysics strictly is earth physics; and the term is used broadly to include a wide range of sciences: hydrology, meteorology, geodesy, seismology, terrestrial magnetism, vulcanology, all of which are united by a bond of interest in some special phase of the physics of the earth. The applied geophysical methods which are used in prospecting for oil comprise a special group of four main methods: the seismic, the magnetic, the gravitational, and the electric (inclusive of the electro-magnetic) methods, which consist in the application of extremely sensitive physical instruments and special physical techniques to the problem of mapping concealed geological features.

CONTENT OF PETROLEUM GEOPHYSICS

Each of the methods follows essentially the following general procedure:

(1) Measurements are made, with appropriate instruments of sufficient sensitivity, so that a survey can be made, horizontally or vertically, of the variation of some physical quantity due to unseen causes beneath the surface of the earth.

(2) From the data of that field survey, certain conclusions can be drawn in regard to the subsurface variation of some corresponding physical property. The distribution of physical properties in areas of undisturbed horizontal beds tends to be constant horizontally within any single formation, but to vary vertically from formation to formation. Structural deformation produces deformation of that horizontally uniform distribution of physical properties. Irregular distribution of certain physical properties, therefore, gives a clue to geological structure.

(3) If the subsurface variation of the physical property is correctly interpreted, it is possible in many cases to draw certain conclusions in regard to concealed geological features.

(4) From the interpreted subsurface structure, the oil geologist can draw certain conclusions in regard to the possibilities of the occurrence of commercial deposits of petroleum.

The physical quantities whose surface variation is measured by those four methods are : (*a*) in the seismic method, the travel time of artificial seismic waves; (*b*) in the gravitational method, the relative intensity of gravity, the horizontal gradient of gravity, and a function of the curvature of the level surfaces; (*c*) in the magnetic method, the relative intensity of the vertical component of the terrestrial magnetic field, less commonly the horizontal component; the angle of dip, and rarely the declination; and (*d*) in the electrical methods, some quantity associated with electrical or electromagnetic fields, either natural or imposed.

The physical properties which correspond respectively to these physical quantities, and whose distribution in the subsurface is interpreted from the variation of the corresponding physical quantity at the surface are : (*a*) in the seismic method, the velocity of transmission of seismic waves in the rocks of the subsurface, especially sharp discontinuity of that velocity at the boundary of formations; (*b*) in the gravitational method, the relative densities of the subsurface rock masses; (*c*) in the magnetic method, magnetic permeability and less commonly the permanent magnetism of the subsurface rock masses; (*d*) the electrical resistivity or conductivity; and in the electrical logging of wells, either resistivity, or potential differences due to electrolytes.

These geophysical methods fall more or less into contrasting groups. In the one, the geophysicist uses an artificial stimulus, has considerable flexibility in applying it, and thus can focus its application upon the feature in which he is particularly interested. In the other he has to make use of a natural field, and cannot focus his application, but has to observe the sum total of the effects as he finds them. Thus, a single magnetic or gravitational observation consists of some measurement at a single point in space. The measured quantity is due to the combined effects, at that point, of small irregularities close to the instrument; of local structural features; of regional variations; and of the earth as a whole. The geophysicist, therefore, must interpret the whole complex system in order to interpret the local structural feature in which he is interested. Such a method has the disadvantage that it may 'see' and give too much, such as geological features hopelessly below the depths in which the petroleum geophysicist is interested. Observations may be made at many places, but everywhere there is the same composite gravitational or magnetic field, which the geophysicist has no power to alter. A single seismic or electrical observation (except in electrical logging) consists of observation between two points whose position and distance apart are controlled at will by the geophysicist. The depth to which the method 'sees' at any observation is dependent upon the distance between those points and upon the amount of energy which the geophysicist chooses to put into the ground. The seismic geophysicist has the choice between the refraction and the reflection methods; and the electric geophysicist has the choice between a considerable series of different techniques. In the use of these latter two methods, the geophysicist uses an artificial field of energy, and can vary its intensity within certain limits at will, and he can vary his application of them in each case in the attempt to get sharper and clearer results.

The contrast extends also to the distinctness and sharpness of the interpreted picture of the structure. The structural picture which is obtained from gravitational and magnetic surveys is generally 'hazy' or indeterminate. Variations from the normal may be termed anomalies, and these depend upon the mass and the position of the causative bodies. The gravitational anomaly may not be entirely due to structure, but may be due to changes of density also. It is not usually a case of a single body with an excess or defect of density, but of a series of such bodies at different depths, and the observed anomaly is due to their integrated effects. It is not possible even with a single body to obtain a unique solution, for a similar body of eight times the

volume at twice the depth and with equal excess density might produce the same gravitational attraction. In fact, a series of a larger number of bodies, within certain finite limits, corresponds to every gravitational or magnetic anomaly. The limits may be so close together as to give a solution which is almost unique, or they may be too far apart to obtain a definite solution.

A much sharper picture of the structure is given by the seismic method. The seismic anomalies which are used depend upon discontinuity in seismic velocity at the boundaries of formations, and by manipulation of his technique the seismic geophysicist can limit his effects to those of the discontinuities above any chosen depth, and can intensify the effects from chosen horizons. The formulae and procedure which are used in the interpretation in practice give unique solutions.

The statement that the seismic method gives unique solutions, however, is not quite true. The formulae which are used in general are only crudely approximate, and they are based on the assumption of straight line paths, although the actual paths are curves. The velocity relations in the rock masses traversed, furthermore, are known only approximately. The personal element enters considerably into the reading of many reflection seismograms; and all reflection seismograms will not be read alike by different geophysicists; the different sets of readings may give radically different solutions; and as a matter of practical experience in the Gulf Coast, seismic crews of different companies get considerably different, in some cases radically different, pictures of the same structure. Different parties of the same company, using identical technique and equipment, may get different pictures of the same structure. The position of the first recognizable impact in refraction seismograms may depend upon the size of the shot. The presence of low-speed beds of at least moderate thickness, intercalated between higher-speed beds, precludes unique solutions in the refraction method. But in areas in which a good seismic key-bed is present and in which many wells go to that key-bed, accurate unique solutions may be obtainable with the reflection method.

These geophysical methods in the main are an indirect method of prospecting for petroleum. The seismic, magnetic, and gravitational methods are indifferent to the presence or absence of petroleum. A commercial deposit of petroleum, theoretically, will produce a disturbance in the distribution of seismic, magnetic, and gravitational properties, but quantitatively the magnitude of disturbance is so extremely small as to be non-observable, for the volume of petroleum in a petroleum deposit is relatively minute. Some highly refined electrical method ultimately may be perfected for the detection of petroleum in advance of drilling. Several methods have been advertised as able to detect petroleum directly in advance of drilling, but as far as the author knows no one of those methods has been proved to be usable as yet. The possibility of the use of an electrical method for the direct determination of the presence of petroleum in advance of drilling depends upon the high resistivity of petroleum, but the electrical logging shows that, practically, beds with high resistance are common in many oil areas; and in the Gulf Coast electrical logging of wells was not successful so long as it logged only resistivity. The possibility of the perfection of an electric method for general or broad applicability to the detection of petroleum in advance of drilling, therefore, seems small, although locally, electrical methods may be able to detect shallow oil and gas sands. The method of electrical logging does have a high degree of ability to detect the presence of oil or gas and to distinguish between salt-water, oil, and gas sands. But the method is applicable only in wells. The geophysical methods, except that of the electrical logging of wells, are not concerned with the direct detection of oil or gas, but merely with mapping of geologic structure.

HISTORY OF PETROLEUM GEOPHYSICAL METHODS

The use of the geophysical methods in prospecting for petroleum is less than two decades old, although the applied geophysical methods are much older; the magnetic method has been used for centuries in the search for magnetic iron ore; the first attempt to apply an electrical method to prospecting for minerals was made more than fifty years ago. Field surveys with the torsion balance were made in the eighteen-nineties. The first application of the geophysical methods in oil geology was a torsion-balance survey by Baron Eötvös of the Egbell oilfield, not far from Vienna, in 1915–16. From his studies of the domes, some of them gas bearing, in Transylvania, and from Baron Eötvös's torsion-balance profile across a part of Transylvania, Hugo de Boeckh recognized the geological significance of Baron Eötvös's measurements, and suggested the survey of the Egbell structure to see whether a torsion-balance survey would detect the petroliferous structure. In 1917 Baron Eötvös started his surveys in the Hungarian Plain, but no immediate practical results seem to have come from those surveys.

The real trial of these methods in petroleum prospecting began after the close of the World War. In September 1920 Mintrop made the first seismic survey for oil, at the gas-well at Neuen Gamme near Hamburg in north Germany, and followed it in October with a survey on the petroliferous Wietze salt-dome in the north German plain; and in 1921 and 1922 he made several small surveys for petroliferous structures in Austria, Baden, and the north German salt-dome oilfield area. The first considerable, and at first rather disappointing, trial of the method came in 1923, when he was brought by El Companie Mexicana de Petroleo, El Aguila (formerly the Lord Cowdray Company, and Mexican subsidiary of the Royal Dutch Shell), to the Golden Lane district of Mexico, and later in the year by the Marland Oil Company to Oklahoma and to the Powell fault-line district of Texas; and early in 1924 he was taken to the Texas–Louisiana Gulf Coast by the Marland Oil Company and the Gulf Production Company. In the meantime, the Anglo-Persian Oil Company, acting through the D'Arcy Exploration Company, obtained an exclusive oil and gas concession in 1921 for the whole of Hungary, and for two years employed the entire personnel of the Eötvös Geophysical Institute in making torsion-balance surveys in Hungary, and in 1923 sent a party from that Institute to India. In February 1922 the Royal Dutch Shell put a German torsion-balance party into the field in Egypt. In 1922 De Golyer, acting for the Amerada Petroleum Corporation and El Aguila, introduced Hungarian torsion-balances, and a month later the Royal Dutch Shell brought German torsion balances into the Texas-Louisiana salt-dome area. Early in 1923 El Aguila began torsion-balance work on the salt-domes of the Isthmus of Tehuantepec in Mexico. The modern magnetic method dates really from F. Schuh's mapping of the Lübteen salt-domes of north Germany in 1919. Minor application of this method in oil prospecting may have been made during the

next few years, but this is not known to the writer. Trial of the method was begun in America in 1924 under De Golyer of the Rycade Oil Corporation and the Amerada Petroleum Corporation (Lord Cowdray Companies). The first application of the electrical methods was in Roumania in 1923 on the problem of mapping the deformation of the base of the Quaternary gravels over a deep salt-dome in the Roumanian plain.

The extensive, practical application of the methods began early in 1925. Knowledge of the methods previous to 1924 was not widely spread, and until late in 1924 no startling successes had been achieved by them. By the end of 1924 German consulting geophysical companies and instrument makers were advertising the methods and instruments widely. In March 1924 the Nash salt-dome was discovered by the torsion-balance method; in October the Orchard dome was discovered by the seismic method, and the Long Point dome by the torsion-balance and seismic methods. The discovery of salt-domes in the Gulf Coast by ordinary methods of prospecting had become most difficult, and the current value of a new dome was between $500,000 and $1,000,000. The discovery of three salt-domes in relatively quick succession brought the technical value and commercial importance of the geophysical methods sharply to the attention of American oil companies. With the beginning of 1925, the use of the torsion-balance and seismic methods began to expand rapidly in America. In May 1925 the Amerada Petroleum Corporation founded the Geophysical Research Corporation, which rapidly began to take a commanding position in the application of the seismic method. The electrical induction seismograph and the wireless transmission of the time of the shot were immediately introduced by that company, and ultimately replaced respectively the mechanical seismograph and the inaccurate air-wave method of determining the time of the explosion; and made possible the brilliantly successful whirlwind refraction campaign of reconnaissance for shallow domes in Texas and Louisiana during 1927, 1928, and 1929, which covered marsh and inland and coastal waters as efficiently as dry land.

The first crude practical use of the reflection method was begun by the Geophysical Research Corporation in Oklahoma as early as 1926, although much pioneer experimentation with the method had been done by Karcher, Eckhart, McCollom, and Haseman in 1921; but the method was not perfected to a reliable and efficient field method, by that company, until 1929. The use of the reflection method then spread rapidly in the mid-continent petroleum area of the United States, but extensive use of the reflection method in the area of the unconsolidated beds of the Texas–Louisiana Gulf Coast did not begin until 1932. Other geophysicists, both American and European, developed seismic instruments and technique, but none of these had an effect on the development of seismic prospecting comparable to that of Mintrop in his commercial application of the refraction seismic method, and that of the Geophysical Research Corporation in subsequently perfecting that method, and in developing the reflection method.

By 1927 the magnetic method was in extensive use in North America, on account of the relative inexpensiveness of the instruments and of the magnetic surveys, and on account of the deceptive semblance of simplicity in observation with the magnetic variometer.

By 1931, in North America, the refraction method had successfully finished its task of rapidly discovering all the salt-domes which rise above a depth of 5,000 ft. in the Gulf Coast; it had not proved well adapted to prospecting for deep salt-domes or for mapping other structures than salt-domes; the use of the seismic method was still increasing; the use of the torsion balance had dropped slightly, chiefly outside of the Gulf Coast of Texas and Louisiana; the use of the magnetic method had greatly decreased; after many trials the American oil companies discontinued the use of the electrical methods as they were found to be inferior to the seismic and torsion-balance methods.

In the meantime, in oil areas outside of North America the Royal Dutch Shell Oil Company and the Anglo-Persian Oil Company had expanded their use of the geophysical methods in practically all areas in which they were working. The Russians were paying much attention to the application of the geophysical methods in oil work. Most large and many small oil companies throughout the world had begun to use geophysical methods.

The second great advance in the petroleum geophysical methods, after their first introduction, was the perfection of the reflection seismic method.

The third great step was the perfection by the Schlumbergers of their method of electrical logging of oil-wells, a method which is not yet fully appreciated, but whose importance will continue to grow.

At the time that this is being written the reflection seismic method, the gravitational method (chiefly the torsion-balance method), and the electrical logging of wells are in extensive use throughout the oil areas and surmised oil areas of the world. A moderate amount of magnetic mapping, and according to report, a certain amount of electrical mapping is being done.

THE SUCCESS OF THE METHODS

The Methods Collectively.

The success of the geophysical methods has been more than sufficient to win them a permanent place among the many methods which the oil geologist must use in prospecting for petroleum. But neither separately nor collectively are they a panacea for the difficulties of the discovery of petroleum. No one of the methods can determine from the surface whether petroleum is present or absent, although after a well has been drilled, the Schlumberger electrical log gives fair criteria for the presence of gas, oil, or salt-water in the sands within the vertical zone which has been logged. The geophysical methods have much in common with the purely geological methods in prospecting for petroleum. In both cases the search for petroleum is made indirectly by mapping geological structure. Each works brilliantly in some areas, moderately well in others, and poorly or not at all elsewhere. And one method may work well in an area or on a problem on which another one of the methods may work poorly; and vice versa. But although limited in scope, the geophysical methods have proved their ability in many areas to reduce greatly the chances against the oil prospector in his hazardous search for petroleum.

The success, but not the use, of the methods will probably reach a maximum within the next few years in North America and Venezuela. A law of diminishing returns applies to the success of practically all geological and geophysical methods; the most easily discovered structures are found first, and then the geologist or geophysicist must work with the more difficult and less definite structures; and in general the increase in his experience and knowledge and in the perfection of his instruments does not

compensate for the necessity of discovering and mapping the more difficult and indefinite structures. The tempo of the search for petroleum is increasing, in spite of the present over-production; and if the oil prospector wishes to continue the discovery of petroleum in the future, he must be willing to drill progressively poorer and deeper prospects and to have a steadily increasing number of failures. Increase in the perfection of the instruments and in the efficiency of the geophysicist is still compensating for the increase in the difficulty of discovering and mapping structure, and will continue to do so on the whole for a very few years more. But then the ratio of successes to failures should begin to drop, although on account of the increased necessity of discovering petroleum, the use of the geophysical methods should continue to increase. The Schlumberger and similar methods of electrical logging may be a partial exception to the preceding postulates. It will be a long time before oil-producing regions are fully drilled, and for a long time every additional well which is drilled and logged electrically will increase the possibility of discovering structure by subsurface correlation and study with the electrical logs.

Seismic Method.

The refraction method had brilliant, almost clairvoyant, success in reconnaissance for salt-domes which rise within 5,000 ft. of the surface in the Gulf Coast of Texas and Louisiana. The brilliance of that work in speed, success, and indifference to the difficulties of marshy and watery terrain probably will never be surpassed anywhere by any method. In that campaign of 1924–30, probably not more than two, and possibly not that many, shallow domes were missed in south-eastern Texas, southern Louisiana, and south-western Mississippi. The method now is known to have been doing good work in detecting the presence of uplift above the deep salt-domes, in spite of the crude technique of that day. The refraction method did good, but not brilliant, work in many other areas of the world in mapping structure and exploring the stratigraphic section in areas without deep wells.

The refraction method has a permanent place in petroleum geophysics. Although out of fashion at present, it may come back into more extensive use for certain tasks. The refraction method in general has definite superiority over the reflection method in determining the seismic section and the major features of the stratigraphic section down to depths of 7,000 ft. in areas without available deep wells, and in following and not jumping key-beds. It is therefore useful in mapping structure, and for some areas and for certain tasks it is preferred by some geophysicists to the reflection method. The technique of the refraction method is capable of further improvement. The technique in general use was designed for rapid reconnaissance of large anomalies and is crude in the light of the modern reflection technique, which is designed to make use of anomalies of thousandths of a second rather than of anomalies of a few tenths to many hundredths of a second. With the increased experience of the geophysicist and with the feasible extended refinement in technique, the efficiency, power, and field of usefulness of the method should be greatly extended.

The limitations to the refraction method are several. The method in general is not practicable for work to depths greater than 7,000 ft., for the costs and the technical difficulties begin to rise rapidly as the distance from shot-point to receiver exceeds 8 miles. The refraction equipment is more bulky and more difficult to handle than the reflection equipment in areas where continuous transportation by boat or automobile is not practicable; and the service of supply of the dynamite is difficult in inaccessible areas. The use of large charges of dynamite in well-settled areas produces many problems in dealing with the people and in the avoidance of actual or alleged damage to property and persons. The costs are greater in the refraction method than in the reflection method, and the efficiency in many types of detail mapping of structure is not as good.

The reflection method has had a brilliant record in the mapping of the top of the Viola (Ordovician) limestone in Oklahoma. The method has yielded fair results in the mapping of most types of petroliferous types of structure in the other oil areas of North America, but its record of success is not so consistent or so brilliant as in the case of the Viola limestone in Oklahoma; and in a few areas reflections are obtained with difficulty. The method works best on smooth structures with low or moderate dips. In thick sections of apparently homogeneous beds, such as those in the Texas–Louisiana Gulf Coast, it leads to good results in picking up usable seismic key horizons at various stratigraphic depths. It works least well on very complicated structure, on faults and badly faulted structure, and on steeply dipping beds. The technique of handling the so-called 'weathered zone' or 'aerated' 'super-water-table', or 'surface low velocity' zone which is strongly developed in some areas, has not been wholly mastered as yet.

Geologically, the reflection method has certain inherent limitations. It is based on the use of the determination of the dip or the depth, or both, of a seismic horizon, or several seismic horizons, at a discontinuous series of points. The reflections from most seismic key horizons do not have any characteristic feature which is distinctive of the reflecting horizon. The correlation of key horizons from one determination point to another in many areas involves the same guessing as in correlation from driller's log to driller's log, if no good lithologic markers and no palaeontologic data are available.

The reflection method has an extensive future before it. The skill of the seismic geophysicist in the application of his method and in the interpretation of its results is still growing rapidly; and in the writer's belief, the science and art of seismic prospecting are still young and will expand greatly in the future.

Gravitational Method.

The gravitational method has had good success, chiefly in the location of salt-domes. Detailed regional reconnaissance with the torsion balance in the Texas–Louisiana Gulf Coast would have discovered all but one or two of the shallow domes actually found by the refraction method on dry land and in most of the marsh country; and at the same time would have discovered the deep domes whose presence was not indicated or was very poorly indicated by the refraction surveys. Moreover the cost would have been less! But the torsion balance could not compete with the seismic method in speed, and in the practical advantage that the geophysicist could survey tracts several miles in diameter without going on them and, therefore, without paying for permission to prospect them.

The gravitational method has had moderate success in mapping non-salt-dome structures such as the Era–Munester–Nocona crystalline Ordovician ridge of north Texas and southern Oklahoma; the other major structures of southern Oklahoma, such as Healdton and Hewitt; the

Hendricks field in Winkler County, Texas, a structure on the top of a massive limestone field; Hobbs in Lea County, New Mexico; Lost Hill, San Joachin Valley, California.

Torsion-balance data which were well taken will never be obsolete as torsion-balance observations, and will be equally as usable as modern observations. The older observations with seismograph, magnetometer, and pendulum are somewhat obsolete in comparison with modern observations.

The pendulum and gravimeter will supplement, but will never replace, the torsion balance as the mainstay of gravitational prospecting under the more skilled interpreters. In areas in which fair torsion-balance results are obtained, the method gives the variation of relative gravity as well as does the pendulum; but the gradient gives a sharper picture of certain types of structure than does the relative gravity; and the differential curvature is particularly valuable in the interpretation of certain structural features; but many interpreters who specialize in gravitational prospecting are not competent to use the differential curvature.

Magnetic Method.

The magnetic method has had a modicum of success and probably is qualified for a slightly larger place in petroleum geophysics than that which is accorded to it at the present time. Magnetic surveys of proper accuracy are not easy to make, and their results are not so easily interpreted as they were commonly thought to be during the American boom in magnetic prospecting several years ago. The magnetic method has a definite field of usefulness in petroleum geophysics. It may be used with success in the detection and mapping of many undesirable volcanic intrusions, which may form the cores of structures; or the so-called 'serpentine' plugs of the Luling district, Texas, whose porous altered volcanic rock is the reservoir rock; or the buried crystalline ('granite') ridges, at least approximately. If a relatively permeable bed of considerable thickness lies at moderate depth below less permeable beds, structural deformation will produce a mappable magnetic anomaly at the surface. The method has the disadvantage that variation of magnetic permeability within the basement, and depositional variation of magnetic permeability in the sedimentary rocks, are greater than the variation of density, so that magnetic surveys show large anomalies of magnetic premeability which have no relation to structure. It is usually impossible to discriminate between the anomalies of structural and those of non-structural origin, at least by simple inspection. However, analysis and approximate calculations may throw some light on this matter. An advantage of the method is the ease, quickness, and cheapness with which a magnetic survey of a whole region can be made. A regional magnetic survey supplementary to extensive torsion-balance and seismic surveys is relatively inexpensive, and yet may give valuable additional information about the framework of the regional structure and possibly may give clues to local structures. The author is inclined to recommend a regional magnetic survey to supplement an extensive regional reconnaissance with the torsion balance.

Electrical Methods.

The electrical methods (inclusive of the electromagnetic methods, but exclusive of electrical logging of wells) have been shown to be moderately successful in the mapping of geological structures in prospecting for petroleum. As the result of extensive trials with the methods, the American geophysicists have come to the conclusion that in combined efficiency and cost the electrical methods are inferior to the seismic and torsion-balance methods. The electric methods have found little place in petroleum geophysics in America. They probably would have been of service, however, if the other methods had not been available. Considerable use of the methods is reported from Europe, but the author has no unbiased information in regard to the actual value of the results which have been obtained. The difficulties in the use of the electric methods increase with depth.

Electric methods have been advertised as capable of directly locating petroleum in advance of drilling. But as yet these claims do not seem to have been substantiated. According to the author's belief, some one or more of the methods may prove to be capable of mapping crudely the presence of petroleum deposits at a few hundreds of feet of depth in specially favourable areas, but in general, in most areas, and at moderate or great depth, the electrical or electromagnetic methods will not be able to map the presence or absence of petroleum.

The Schlumberger method of electrically logging wells is showing a high degree of success. Experience with it is still immature. The instruments, the technique of their use, and the interpretation of the electric logs are still being perfected. The limits of the field applicability of the electrical logs have still to be determined. The method has shown great power (*a*) in providing data for stratigraphic correlation, and (*b*) in detecting oil and gas sands, and in discriminating between them and salt-water sands. The electrical log has the advantage over the ordinary driller's palaeontological log in being continuous and not dependent in general on cores at more or less frequent or infrequent intervals, and in being independent of the presence or absence of fossils, particularly key fossils, within the relatively small space of a recovered core. Some of the author's colleagues, who have had much experience with the method, are discussing whether it may not be advisable (*a*) to abandon coring in the first wildcat and to depend upon the electrical log to detect the presence of oil and gas sands, and (*b*) to core only after production has been obtained, in order to identify the electrical key horizons, but as yet no one has adopted that practice. The power of the method to indicate oil and gas sands is known to be high, but how high is still a question which must wait for experience.

Other Methods.

Various further methods of less importance such as surveys of radio-activity and of earth temperature have been tried. Relations between the variation of earth temperature and structure have been demonstrated. None of these minor methods as yet, however, has been shown to be of practical, commercial importance.

The use of new and unconventional instruments, or methods, should be regarded sceptically by the oil prospector until the instrument or method has been approved, at least tentatively, by competent petroleum geophysicists (not all practising geophysicists in good standing will be competent to pass judgment). Useful new instruments and possibly a useful new method or two will be devised in the future. But in addition to instruments and methods which are faulty in principle, many instruments and methods will be proposed to the prospector which are almost good enough, which basically are sound in scientific theory, but which cannot attain the precision of measurement necessary

for the purpose for which they are devised and for which the oil prospector would use them.

Black Arts.

The success of the 'Black Arts' methods—witchwands, wigglesticks, dowsing, human reactions to mysterious rays or emanations—to find petroleum (or anything else) has still to be demonstrated to the satisfaction of the geophysicist in spite of the great antiquity of some of those methods. Wells which have been located by one of those 'Black Arts' methods, to be sure, have discovered deposits of oil and gas. But many wells which were located entirely by chance have discovered oil- and gas-pools also; an important West Texas oilfield, Big Lake, for example, was discovered because of a break-down of the transport equipment; the well was drilled at the place of the breakdown, while a subsequent test-well at the original location was dry. The geophysical methods are based on known scientific theory and data, and can be, and have been, repeatedly justified to and accepted by disinterested physicists. The 'Black Arts' methods postulate the existence of rays, emanations, attractions which either are unknown to science, or which postulate properties other than those which they are known by science to have. The whole basic theory of those 'Black Arts' methods is scientifically unsound. The practitioners of the 'Black Arts' methods rarely have consented to proper scientific tests of their methods; in the few tests under proper scientific control, the methods have not detected petroleum or thrown light on geological structure.

ORIENTATION IN A NEW AREA

Geophysical orientation in regard to an area is as necessary to the geophysicist as geological orientation is to the geologist. Many executives and geologists make the mistake of failing to realize that a geophysicist cannot go into a new area, about whose geophysical make-up he knows nothing, and begin immediately to turn out competent interpretation of structure. In an area about which he knows little or nothing, the geologist must spend some time in a preliminary study of the stratigraphic section and of the general geological framework of the region before he will feel himself competent to attempt the mapping of particular structures. In the same way, the geophysicist requires time to orient himself geophysically in a new region. As with the geologist, there are a few areas in which certain anomalies stand out so clearly and definitely that the geophysicist may feel justified in their immediate interpretation. But in general the seismic geophysicist must work for some time in an area before he can make reliable interpretation of his data. He may have to make several trials before he learns the trick of getting usable reflections. He must then work out his seismic section and learn, if possible, what usable seismic key horizons are present, how to recognize them apart, how persistent they are, and whether there is danger of a mistaken jump from one to the other among some of them. The seismic geophysicist and the stratigrapher are much alike; the speed and sureness of each in his correlation increases with his knowledge and experience in the area. It may take the seismic geophysicist several months, a year, or even longer, to get the hang of working the area. In gravitational and magnetic prospecting a wide areal reconnaissance survey of the region is necessary before the geophysicist can begin to make intelligent interpretation of particular features.

Geophysical orientation depends greatly on geological orientation; and the geophysicist usually needs some knowledge of the geology of the area in order to choose between various interpretations which are equally possible mathematically. In an area where the geology is little known, the geophysicist may have to wait for the drill to check his predictions and to help him to complete his orientation.

It is most important for the petroleum prospector to realize that the geophysicist is not clairvoyant and cannot dash into a new area and begin immediately to turn out competent mapping of structure.

CHOICE OF METHOD

The oil prospector should endeavour to fit his choice of method, or methods, to the particular problem in hand, with due regard to the general situation and to the money and time which he has available. The methods selected must be suitable for the area and for the immediate problem. The prospector's choice will be guided also by the technical advice of the geophysicist.

The range of tasks to which geophysical surveys may be applied is wide, for example: (*a*) regional reconnaissance to map the structural framework of a large area; (*b*) regional reconnaissance of a relatively virgin area to determine the more conspicuous structures; (*c*) more local clean-up reconnaissance of the less conspicuous structures in an area in which much geological and geophysical exploration has already been completed; (*d*) surveys to prove, or disprove, the presence of some local structure; (*e*) surveys to detail known structures; (*f*) surveys to check inconclusive suggestions of structure by other methods; (*g*) research surveys; (*h*) guerrilla sharp-shooting on competitor's prospects; (*i*) logging of formations and of oil and water sands in wells.

The physical problem before the survey is a factor of paramount importance in the choice of the method. The geophysicist must decide what types of structures are to be expected, and the kind of physical situation that will arise. For example, salt-domes may occur under a variety of conditions; thrust through an enormous thickness of unconsolidated sand; rising through limestone, sandstone, or anhydrite; surrounded by sediments of relatively high magnetic permeability; or resting on anticlines of diatomaceous or other shale. Physical conditions have a wide range of variability also, in such cases as—buried ridges of granite, or limestone, or shale; faults, folds, and intrusions. The geophysicist must not only decide what physical situation is to be expected, but how sharp and intense the respective anomalies in magnetic permeability, in density, and seismic velocities will probably be. If the anomaly of only one of those types of physical situations will be definite, only the corresponding method can be used; the so-called 'serpentine' 'plugs' of the Austin district of Texas, for example, are detected efficiently only by the magnetic method. But many types of structures produce workable anomalies of more than one type, and therefore, more than one method can be used; reconnaissance for shallow salt-domes in the Gulf Coast, for example, is feasible either by the torsion balance or by the refraction method. The same situation may require different methods in order to obtain information on specific points. The torsion balance, for example, is superior in reconnaissance for deep salt-domes in the Gulf Coast, but the reflection method is superior in detailing the deformation on horizons within the range of producing depth. Again, the refraction method

was a most brilliant success in rapid and efficient reconnaissance for shallow domes, but the torsion balance was superior in detailing the crest of the dome.

The terrain technically precludes or limits the application of a method or methods in certain areas, and economically affects their use in varying degrees. The seismic method is the only one of the methods which works essentially with equal technical success on land, on marsh, and in water. Torsion-balance surveys have been, and can be, made in shallow bodies of water, if the necessity for the data justifies the expense. A magnetic survey in the same way can be made under those conditions, but the author doubts whether the cost of such a magnetic survey would ever be justified. Too rugged relief precludes torsion-balance work; and the differential curvature is more easily affected than is the gravity gradient. The seismic method does not work well in some areas in which the so-called 'weathered' (or 'aerated' or 'low velocity') surface velocity zone is strongly and irregularly developed. The terrain, of course, greatly affects the ease, and thereby the costs, with which surveys by the different methods can be made. A magnetometer is carried easily wherever a man can go. The transportation of the torsion balance is much more complicated under unusual conditions of terrain, but is entirely feasible even if everything has to be transported by porters. The transportation of the reflection equipment is a little more complicated than that of the torsion-balance if the equipment cannot be permanently mounted on wagons or boats, but is entirely feasible. But the difficulties of service of supply of dynamite for the refraction method might easily preclude use of that method in difficult country. The lie of the land, furthermore, may limit the geophysical surveys, which may be possible along valleys through rugged mountains, but may be impossible on the mountains. Over a large area of the Llanos of Venezuela the linear north-west to south-east pattern of the drainage makes surveys in a north-east to south-west direction difficult or impossible except at very much greater cost than surveys parallel to the rivers.

Cost is necessarily a most important factor not only in the choice between methods, but also in the decision whether or not any geophysical work shall be done. The probable cost of the work must be weighed in terms of the expected value and usefulness of the results of the work to the prospector. The cost of such work must not be greater than that of some other method of prospecting which will produce results of equal value to the prospector. Several shallow wells, for example, can be drilled on a poor geological prospect at the same cost as a good geophysical detail survey, and if the producing sands are shallow those wells may not only prove the prospect, but, if dry, give as much positive evidence of the structure as the geophysical work. The cost of a reasonably good survey must be within the appropriation which the company has, or can reasonably make, for that purpose; the geophysical work, therefore, must be planned to keep the costs within the financial resources and policy of the company; and a small company may not be able to afford the more expensive methods, even if the probable results would be of high value. The usefulness of the results must be weighed against the cost of the survey, but even if the probable value of the results is low, a survey at low cost may be worth while in order to supplement other geophysical work, for the additional information may furnish one or two clues which will more than repay the expense of a low-cost survey.

Different types of cost must be considered. The gross cost must be used in fitting the geophysical work to the available appropriation and to the financial resources and policy of the prospector. The cost per barrel of oil which is discovered by the method is the ultimate test which will be applied by the average prospector. The cost per structure which is discovered by the method is a technically fairer test of the methods, for with the exception of the method of electrical logging of wells, the methods map structure and not the presence or absence of oil. The cost per acre is valuable in comparing different methods, but care must be taken not to compare cost per acre for reconnaissance by one method with cost per acre for detail work by another method. Speed at times may be more important than cost per acre, and the important cost will be a function of the reciprocal of the time necessary to work a prospect. The gross cost of the refraction seismic method in the Gulf Coast of Texas and Louisiana in reconnaissance for shallow domes, for example, was high, $15,000 to $20,000, per month per party, but the cost per acre was extremely low, although probably not so low as that of reconnaissance with the torsion balance for deep salt-domes and for the roots of shallow domes. But on account of the very great speed of the refraction method—in some cases more than 50,000 acres were covered efficiently in a day—the slightly higher cost per acre in comparison with the torsion-balance reconnaissance was of negligible importance.

Time may be a factor of paramount importance. Concessions and options run only for a limited period of time, which may be very short; and even if the term of the exploratory option be indefinite, the annual or semi-annual payments necessary to maintain the option may preclude time-consuming geophysical exploration. Highly competitive conditions may preclude the use of the necessarily slow-moving torsion-balance method and force the use of the seismic method for reconnaissance of prospects which are not controlled by the company.

One or more of a number of minor factors may have to be considered.

The use of dynamite or any high explosive is taboo in certain countries; or at times of unrest in other countries, its use might be put under too onerous restrictions and regulations for seismic prospecting to be practicable. Popular fear of the damage from the dynamite shots may cause the political banning of seismic exploration in certain jurisdictions.

The patent situation in one country restricts the prospector's choice, unless he comes to terms with the single licensee and believes in the latter's ability and experience with the modern developments of the method.

For some methods and for certain purposes permits to go on a tract are necessary in order to survey it, whereas by another method the survey of the tract can be made without going on it. In the refraction campaign for shallow domes by reconnaissance, in the Texas–Louisiana Gulf Coast, a shooting permit would be obtained for a tract of 20 to 50 acres, if possible; the detectors would be set along the edge of the public roads, and hundreds of thousands of acres would be covered without getting any sort of permit except on a few hundred acres. The gravimeter and magnetometer can in general work along public roads in reconnaissance without going on private land. Torsion-balance stations in general have to be set back away from the ditches and grading of public roads, and therefore have to be set on private land, and permits have to be obtained.

The secrecy with which a survey can be made may be of

importance; the little white torsion-balance houses which have to stand for 4 to 8 hours on a station are most conspicuous; but a gravimeter that works in an ordinary light delivery truck, and which requires from 5 to 10 minutes for the occupation of a station, can work along roads almost wholly unnoticed.

The question whether the possibilities of surface geological work have been reasonably exhausted should be carefully reviewed by the oil prospector. An exceptionally able (company) geologist and two assistants can be kept in the field for a year for the approximate cost of operation of a seismic reflection crew for 6 weeks. A structure based on good surface geology in general is preferable to most geophysical structures (but not all), and good geology may give good but inexpensive reconnaissance clues to structural features, which can be investigated by geophysics. The able geologist may need 6 months or a year to work out his stratigraphic section and criteria to split it into recognizable small units. He and his assistants may not be able to turn out tangible results inside of a year. A seismic crew may (or may not) be able to bludgeon in, pick up a key-bed, and check a prospect in its first 6 weeks in the area. But by the end of the year, the geologist in general will have covered more area than the reflection crew, at a lower cost. Surface mapping for structure is, of course, wholly barren of results in some areas, and in other areas is extremely slow and tedious.

PHYSICISTS, GEOLOGISTS, AND GEOPHYSICISTS

A distinction should be drawn between the physicist, the physicist-geophysicist, the geologist-geophysicist, and the geologist, and their relative functions in, and relations to, geophysical prospecting. Petroleum geophysics is a science which lies between physics and geology, and which uses physical devices to work geological problems. It has two differing types of tasks: the first, inventing and bringing to a workable degree of perfection instruments, techniques, and formulae for solving certain types of geological problems by physical means; and the second, applying those instruments, techniques, and formulae to the working out of particular geological situations.

The physicist-geophysicist ideally differs from the physicist proper in his additional knowledge of geophysical physics, and in an elementary acquaintance with geology. His particular function is the solution of new geophysical problems. Functioning as a geologist-geophysicist, he has the disadvantage that like all elementary students of science he has an over-simplified impression of that science and fails to recognize the many complications, difficulties, and uncertainties which are actually present. The physicist-geophysicist for a long time will have an important place in petroleum geophysics, for the instruments and the physical technique are capable of much further development.

The geologist-geophysicist ideally differs from the geologist in his additional training in mathematics, physics, and geophysics; and he differs from the physicist-geophysicist in being primarily a geologist rather than primarily a physicist, but as a matter of fact, he must be a pretty fair physicist. His particular function is the application of the geophysical methods to the practical working out of particular geological situations. Men of such special qualifications, unfortunately, are extremely scarce. Interpretation in practice is done by geologists who have had insufficient mathematics and physics, or by physicist-geophysicists who have had insufficient geology.

The petrographer is a practical example of how the relations of the physicist and geologist have worked out in one branch of science, which, however, has been geological so long that its geophysical nature has been forgotten. Both petrography and the seismic method, by the use of appropriate physical instruments and technique, draw certain conclusions in regard to the constitution of some section of the earth's crust. The petrographic microscope is as distinctly a physical instrument as the torsion balance, magnetometer, or seismograph. The theory of petrography involves as much (or more) mathematical physics and physics as the seismic, magnetic, and gravitational methods. The petrographer, the man who applies this geophysical method to the study of geological problems, is not a physicist, but is a geologist who has had special training in the physics, mathematics, and special technique and theory of petrography.

The geophysicist most likely to be successful in the long run, will be one like the petrographer, who is primarily a geologist, but who has had sufficient physics and mathematics to understand the physical mathematical theory of the geophysical methods and instruments. He must have been trained also in the special technique and theory of those methods and of the instruments which he uses. No geologist would think of attempting petrographic work with a physicist at the microscope and a geologist at his side to make geological interpretation of the former's physical determinations. The often recommended combination of a physicist in charge of the application of the geophysical methods and a geologist to make geological interpretation of the former's physical findings seems to the writer equally inefficient.

Geophysicists are of many grades; not all who term themselves, or are termed, geophysicists, are such, and not all men with long experience in geophysics are competent interpreters. In making use of geophysics, the oil prospector will be wise to ascertain what sort of geophysicist the man is whom he would employ. The most competent geophysicist, like the geologist, is not omniscient, but in general he is well aware of the difficulties and uncertainties of geophysics, and of the inadequacy of his knowledge. A competent physicist is not necessarily a competent geophysicist or geophysical interpreter, and his physically plausible interpretation may be highly improbable or impossible geophysically, and geologically. A geologist who has had a superficial contact with geophysics may be misled by the seductive resemblance of magnetic and gravitational isogams to structure contours, and may make an interpretation of magnetic or gravity survey which is plausible geologically but wholly impossible geophysically.

Field observers in geophysical work may be highly competent field observers of long experience, but that does not necessarily make them competent interpreters. They often are not aware of how much they do not know about geophysics. There are many 'practical' interpreters, perhaps engineers or geologists, who have attained considerable ability in interpretation through long and broad experience, without having learned much about the underlying theory. Their interpretation of stock solutions is good, but will tend to become inadequate in novel situations. The dowser and the fake, keeping abreast of the times, commonly, nowadays, term themselves geophysicists, and advertise their usually exclusive methods as 'geophysical' methods, even sometimes in the professional cards of reputable technical journals!

CONCLUSION

The applied geophysical methods will be found of great value to the petroleum prospector who uses them intelligently and wisely. They will not remove all difficulties in locating petroleum. If he mistakenly persists in regarding them as a panacea and in attributing clairvoyant powers to them, he is doomed to disappointment in the results of his use of them. But they definitely have shown their power greatly to reduce his difficulties in locating petroleum under a wide range of conditions. The methods as a whole have certain limitations, and each one of the methods has its individual limitations. If the prospector keeps this in mind in his use of the methods, he will tend in the long run to be abundantly satisfied with the results of his geophysical surveys. The methods employed are still young and their limits of applicability have not been fully established; the prospector must remember that those limits can be established in general only by pushing the application of the methods until they fail; and he must also remember that the utility of the methods in a new area in general can be learned only by trying them out. Reasonably good results have been obtained in areas which in advance looked rather unfavourable; and conversely, the methods have given poor results in areas in which good results might be expected. The most important single factor in the successful use of the geophysical methods is, of course, the geophysicist; and the prospector who in the long run will have the best success in his use of the geophysical prospecting will be the one who chooses his geophysicist the most wisely and carefully. And the geophysicist who will have the best success in the application of geophysical prospecting in the long run should be the one who is a geologist of broad training and experience, a fair physicist, and a geophysicist with good training in the theory of the method and with wide experience in its application.

MAGNETIC METHODS

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Introduction

In the light of present knowledge it seems permissible to assume that the magnetic field of the earth is induced somehow in connexion with its rotation and that the magnetic axis of the earth would coincide with its astronomical axis, if it were not for the varying chemical distribution (especially iron-content) and the tectonic dislocations within the magma-zone and the rock-zone of the earth [13, 1933; 29, 1934].

In agreement with the above assumption, the earth's magnetic field may be resolved mathematically into a 'normal' field, with its axis coinciding with the rotational axis, and a residual 'anomalous' field. The 'anomalous' field is found as the vectorial difference between the measured field and the 'normal' field at the respective latitude.

A magnetic vector which is directed away from the earth will be called a negative vector; a vector directed towards the earth, a positive vector; and a vector which has a horizontal direction, a neutral vector. Then a magnetic positive anomaly exists where the vectorial difference between measured and 'normal' vectors is a positive vector, and a magnetic negative anomaly exists where the vectorial difference is a negative vector.

The 'anomalous' field is composed of major positive and negative magnetic anomalies which extend over vast areas of the earth. It is interesting to note that the main trends of these major anomalies show a striking parallelism with the main trends of the alpine orogeny. Thus a positive major trend, which extends through the two Americas in a north-north-west to south-south-easterly direction, runs parallel with the Rocky Mountains and the Andes; a negative major trend, which extends in a west-easterly direction through Africa and the Indian Ocean, swings southwards through Australia, running parallel to the alpine trends of Eurasia and Australia.

Within the area of a continent part of a major anomaly may be designated as a continental anomaly. Thus Europe is magnetically negative, the two Americas are magnetically positive.

Considering the average continental field as 'normal' for a continent, there are large areas of a magnetically more negative or more positive character with reference to that field. Such areas are called regional anomalies. Thus the West Texas Permian Basins or Transylvania are negative regional anomalies; the California Valley or Wallachia are examples of positive regional anomalies.

Taking the average regional field as 'normal' there exist as a rule more localized magnetic disturbances, and these in turn may be further disturbed by intra-local anomalies. A granite ridge, for example, which creates as a whole a local anomaly may be faulted, and thus the 'normal' course of the local anomaly may be disturbed over the fault by an intra-local anomaly.

The major and continental magnetic anomalies are of interest in connexion with theoretical considerations about the nature of the magma-zone and its relation to the rock-zone; the regional anomalies disclose the tectonics and the petrographical character of the rock-zone, and the local anomalies lead to detailed investigations of a tectonic, petrographic, and stratigraphic nature within the uppermost layers of the earth.

Geological and Physical Problems in the Interpretation of Regional and Local Anomalies

Magnetic Susceptibility of Rocks.

The geological interpretation of regional and local magnetic anomalies is based upon the fact that the rocks which constitute the outer crust of the earth vary greatly in their magnetic susceptibility.

The average magnetic susceptibility of basic igneous rocks and of some magnetite-bearing crystalline schists is generally assumed to be from 10 to 100 times stronger than the average susceptibility of sedimentary deposits, granites, and of the majority of metamorphosed rocks [25, 1930].

It is, however, fundamentally wrong to assume that magnetic anomalies are almost exclusively due to igneous rocks. Igneous rocks ('Basement') are buried at depths ranging from 6,000 to over 20,000 ft. in the oil regions of the United States, for example, and the magnetic effect of local structures is about inversely proportional to the square of their depths.

Unfortunately, only a few data about the susceptibility of sedimentary deposits are available to-day. However the susceptibility of some dolomites is from 20 to 50 times weaker than that of some blue shales or ferruginous sandstones; and the susceptibility of limestones is very low if compared with that of shales and sandstones.

Moreover the magnetic susceptibilities of rocks seem to be considerably stronger in the weak magnetic field of the earth than in the strong laboratory fields [27, 1929], and, with increasing temperature, (depth), the magnetic susceptibility increases in such weak fields [7, 1934, p. 160; 30, 1911].

Even though the susceptibility in itself is small, such large relative differences in the susceptibilities of the shallower sediments should fully suffice to create magnetic anomalies clearly discernible with modern instruments, especially if the 'Basement' lies at great depths.

Since this conception is not yet generally accepted, we are glad to cite a few references which strongly support these views.

Weiss [31, 1934]: 'The application of the magnetic method in the Witwatersrand has met with considerable success, especially in the locating of Post Karroo dykes and in determining the approximate location of the sub-outcrop of three very strongly magnetic shale beds in the lower Witwatersrand system: the Water Tower Shales, Contorted Beds, and West Rand Shales. By means of these magnetic key-beds it is possible to delineate indirectly the zone of the approximate position of the Main Reef. The above three magnetic markers can be detected even if they are covered with 1,000–2,000 ft. of younger sediments, and consequently the magnetic method is of great

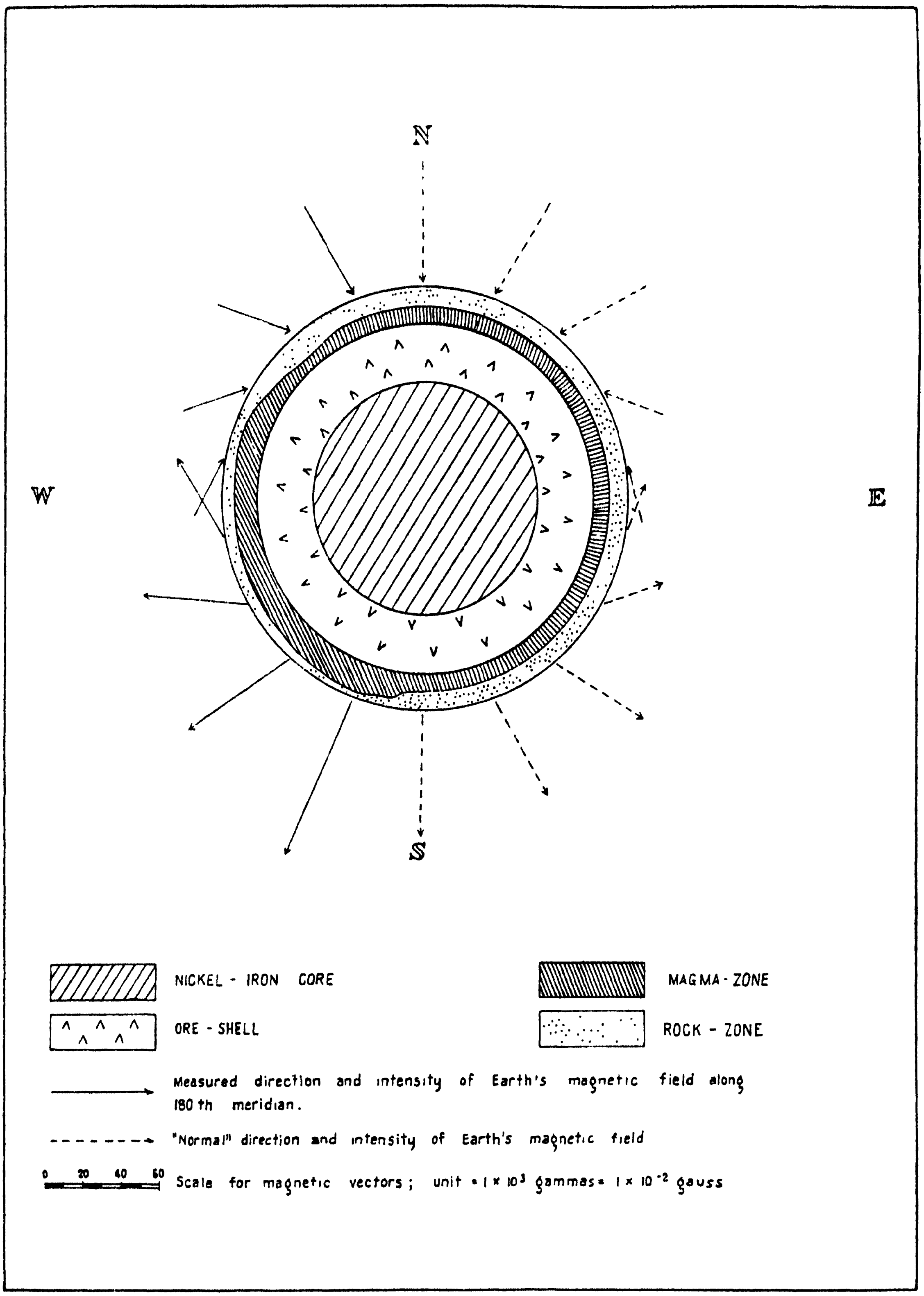

FIG. 1. Structure of the earth, 'normal' and measured intensity and direction of the earth's magnetic field.

value in prospecting areas, where Karroo beds and Dolomites rest unconformably on the Witwatersrand system.' Lynton [22, 1931]: 'General conditions for the use of magnetic geophysical methods in California are good, as there is marked variation in the magnetic susceptibility of the sedimentary rocks of economic interest. In Tertiary rocks, the magnetic susceptibility varies from 14×10^{-6} in the Saugus of the Upper Pliocene to 412×10^{-6} in the vivianitic sandstone of the McKittrick group of the Pliocene. This variation is sufficient to give a definite

magnetic contrast at several horizons. "Magnetic marker beds", such as this vivianitic sandstone, beds of volcanic tuff, and interbedded basaltic flows, extending throughout considerable areas, have been found, which are sufficiently thick and magnetic to cause anomalies of several hundred gammas at surface exposures and recognizable indications under deep cover.'

Rieber [26, 1930]: 'Certain strata in the more recent fresh-water deposits of the Tulare Series, in the San Joaquin Valley, California, which contain material only slightly more magnetic than the adjacent strata, show sufficient magnetic anomalies in the vicinity of known faults and folds to give promise of extensive usefulness of magnetometer surveys in the exploration for oil.'

The basic idea, prevalent in former years, that the magnetic effect is due almost exclusively to the chemical properties or the tectonic dislocations of the 'Basement' rocks underlying the oil areas, has led to many misinterpretations and has in many places discouraged magnetic prospecting, first, because under this assumption the station net was laid out on a too wide scale and therefore would not permit the location of anomalies due to shallow, local influences; and secondly, because the field measurements were not sufficiently accurate.

Stratigraphic, Petrographic, and Structural Anomalies.

Magnetic anomalies may be produced by lateral variations in the ferruginous content of a sedimentary bed, by lateral differentiations of igneous rocks, by thickening or thinning, or by the normal dip of a certain magnetic horizon. Besides these anomalies of a petrographic or stratigraphic origin, magnetic anomalies may be due to structural features. A magnetic shale bed may be brought close to the surface on the up-thrown side of a fault. Practically non-magnetic dolomites may be uplifted along an anticlinal axis and thus displace stronger magnetic shales and sandstones. A nephelinsyenite plug may intrude into much less magnetic sedimentary beds, or old igneous ridges may be covered by sedimentary deposits of a much smaller magnetic susceptibility.

Relationship between Depth and Size of a Disturbing Mass and its Magnetic Anomaly.

It is evident that the lateral extent and the amount of a magnetic anomaly must have some relation to the magnetic susceptibility, size, depth, and structural arrangement of the rocks which produce it.

A number of methods have been developed for the geological interpretation of magnetic anomalies. Though there are a large number of possible theoretical interpretations for any anomaly, yet geological conditions will, as a rule, restrict this number to only a few probable solutions which are compatible with the generally known subsurface conditions.

Lee's Graphical Method. Lee [20, 1932] has published an elegant graphic method for the calculation of the horizontal and vertical magnetic intensity, particularly above dykes and other related geometrical forms. From Lee's study it follows that an extended thin horizontal magnetic layer theoretically has no magnetic effect along the surface of the earth, and that the magnetic effect of an extended infinitely thick horizontal magnetic layer is constant for any depth of the upper boundary of this layer.

Nippoldt's Method. The study of Nippoldt's method [23, 1930], which is based upon a sequence of magnetic poles, is most instructive and elucidates the relationship of structural features with their respective anomalies.

Nippoldt begins with the basic formula:

$$F_E = \frac{P}{r^2},$$

where F = magnetic force, exercised by
P = magnetic intensity of a single pole;
r = distance between the single pole and point E of observation.

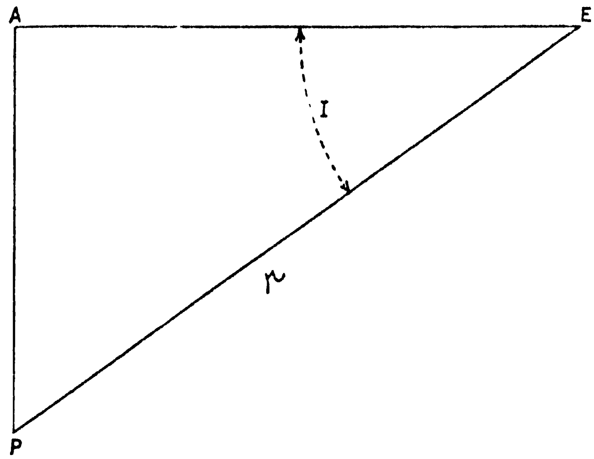

FIG. 2.

If I = angle between r and the horizontal,
Z = vertical component of magnetic force F,
H = horizontal component of magnetic force F,

then $Z = F \sin I$ and $H = F \cos I$.

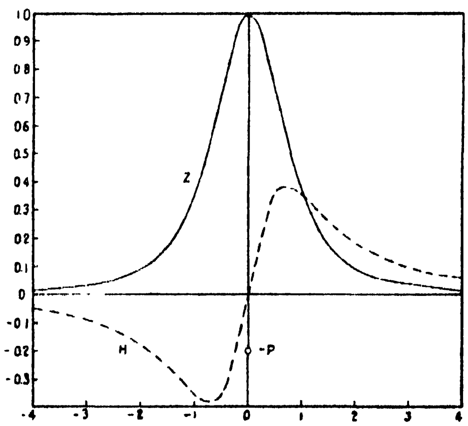

FIG. 3. (After NIPPOLDT.)

Fig. 3 shows the curves for the vertical and horizontal magnetic intensities which are produced along the surface by a unit pole, buried at unit depth. The maximum intensity is directly above the pole and is taken as unity. At about the unit horizontal distance the vertical intensity amounts to about ⅓ of the maximum intensity, whence the old depth rule: The depth to the origin of a magnetic disturbance is equal to the distance between the centre of the magnetic anomaly and the points, where the anomaly is ⅓ of the maximum at the centre.

Fig. 4 shows the curves for the vertical and horizontal magnetic intensities along the surface due to two poles, of which the negative pole is buried at unit depth and

the positive pole at 3 times unit depth. Owing to the negative influence of the lower pole both the Z- and the H-curves are of smaller amplitudes than those of the unit pole.

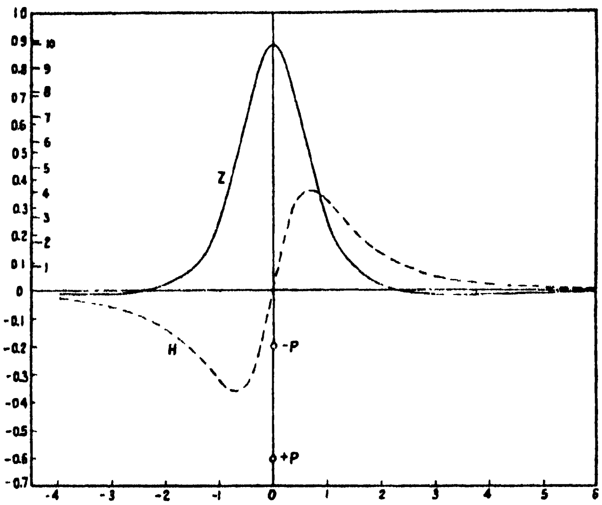

FIG. 4. (After Nippoldt.)

Fig. 5 shows the magnetic curves for a system of pole-couples arranged so that the negative poles lie along the upper side of an inclined plate and the positive poles along the lower side. Such an arrangement should closely approach the actual magnetic influence of a continuous magnetic layer.

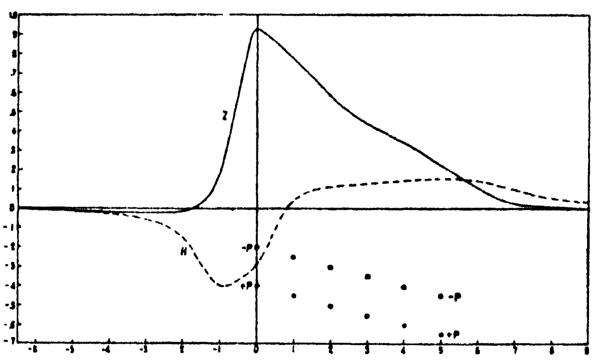

FIG. 5. (After Nippoldt.)

Induction by the Earth's Magnetic Field.

Beds with a high magnetic susceptibility will, as a rule, create positive magnetic anomalies in the northern hemisphere, but occasionally the outcrop of a highly magnetic bed may be characterized by a negative anomaly. Until recently, electrical earth currents, permanent magnetization, &c., were used to explain this phenomenon, though already four decades ago it was correctly assigned to the effect of induction by the earth's magnetic field [6, 1897], the direction and intensity of which are shown in Fig. 1.

Since the rocks are subject to induction by the earth's magnetic field, it follows that, according to the dip and strike of a given ferruginous bed, or on account of its magnetic latitude, various magnetizations may be induced.

Fig. 6 shows the induced polarity of surface outcrops of magnetic bodies in various positions in the earth's field. Broderich [2, 1918] explains that a neutral bar of a magnetic substance, placed parallel to a magnetic field, acquires an induced polarity (*a*), such that the positive pole would be near that end of the bar, to which a free-moving north-seeking pole in the field would move. As the bar is rotated from the parallel position, the polarity becomes related more to the sides and less to the ends, until finally, when the bar is perpendicular to the field, it is entirely related to the sides (*f*). However, if the bar is turned but a few degrees from the perpendicular position, the ends will show some polarity.

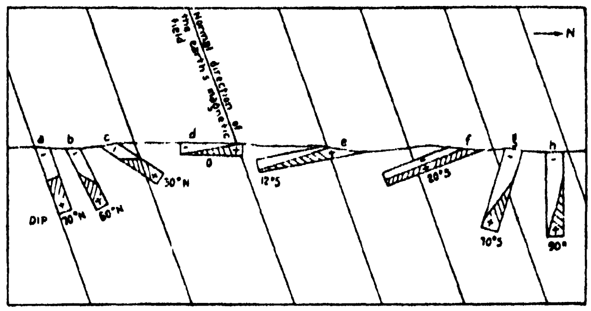

FIG. 6. Induced polarity of surface outcrops of magnetic bodies in various attitudes in the earth's field. (After Broderich.)

Fig. 7 shows schematically the curves of the vertical magnetic intensity over a granite ridge with different orientations and latitudes [15, 1934].

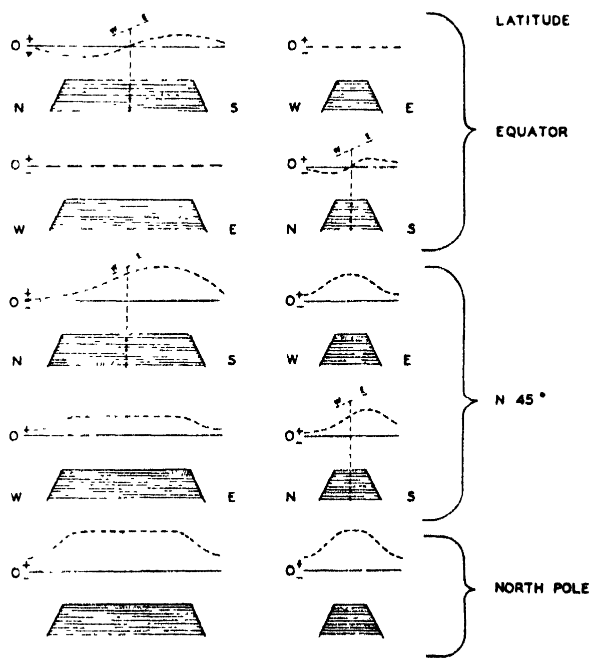

FIG. 7. Schematic curves of vertical magnetic intensity over Granite Ridge with different orientations and latitudes.

Haalk's Method. According to present conceptions, the direction and intensity of magnetization of geological bodies is generally due to the induction by the earth's magnetic field.

Haalk [7, 1934] has developed a method of interpretation of magnetic anomalies which takes into account the direction of the inducing earth's magnetic field. The method is based upon the theorem of Poisson, and makes use of an analogy between the gravitational and magnetic potentials. In this way magnetic interpretation is closely allied to the gravitational torsion-balance methods [5, 1908]. The

drawbacks of Haalk's method, especially for irregular geological bodies, are the assumption of homogeneous magnetization and the tediousness of calculation.

Fig. 8 shows the vertical and horizontal intensities calculated by Haalk for a magnetic dyke which dips (*a*) parallel and (*b*) at right angles to the earth's magnetic field, having an inclination of 45°.

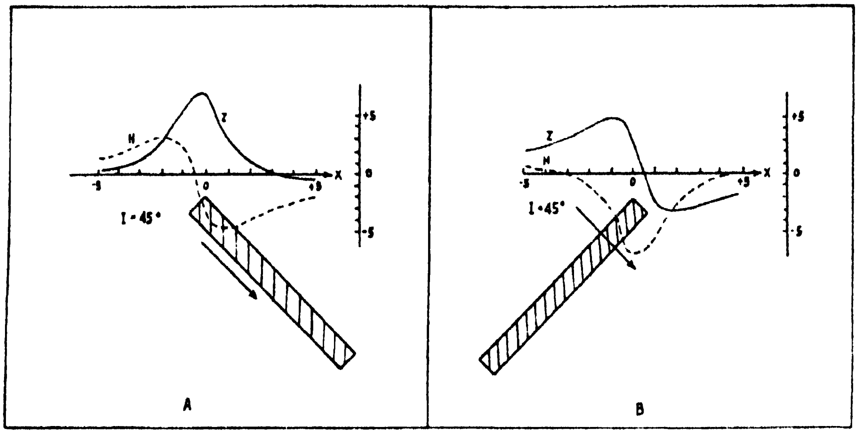

FIG. 8.

Instruments and Methods for Magnetic Observation

Absolute Measurements.

The direction and intensity of the earth's magnetic field is defined by any three of the seven elements shown in Fig. 9.

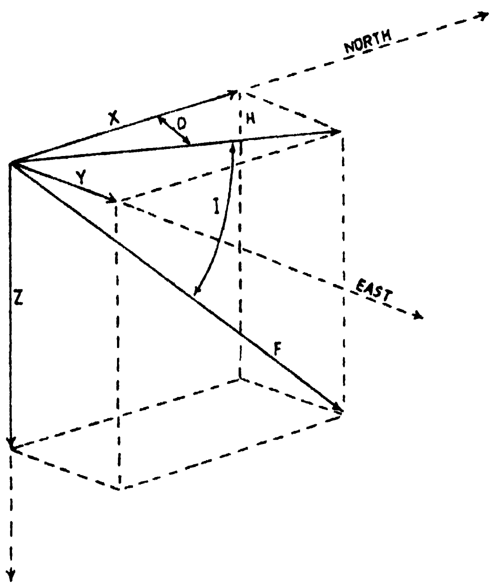

FIG. 9. *D* declination. *I* inclination. *F* total intensity. *Z* vertical intensity. *H* horizontal intensity along magnetic meridian. *X* horizontal intensity along true meridian. *Y* horizontal intensity perpendicular to true meridian.

As a rule *D*, *I*, and *H* are measured; the other four elements are computed from the observed data. *I* is observed with a dip circle or with an earth inductor, *D* and *H* are measured with a magnetometer of special design. The essential part of this magnetometer is a hollow cylindrical magnet which hangs in a horizontal position in a stirrup suspended by a silk fibre or fine metal ribbon. The declination is the angle between true north, as determined by the north star or magnetic north found by the sun, and the cylindrical magnet. From the time of oscillation of the cylindrical magnet and the amount of deflexion produced on an auxiliary magnet, the total horizontal intensity may be computed. A detailed account of the instruments and methods used for the absolute measurements of the earth's magnetic field is given by Hazard [9, 1930].

Relative Measurements.

Applied geophysics is, however, primarily interested in instruments and methods for the relative measurement of the earth's magnetic field. In order to survey in a simple and speedy manner local disturbances of the earth's magnetic field, special instruments (magnetic local variometers) have been designed. The oldest instrument of this type is the Swedish mining compass, which was used as early as the seventeenth century for the location of iron-bearing formations. The old dip-needle has more recently been perfected into the Hotchkiss Superdip. The old Thalen-Tiberg magnetometer and the Lloyd balance have been replaced by the Askania magnetometer, devised by A. Schmidt in 1915. The Askania magnetometer has been gradually improved during the past decade to such a point that it is generally considered to-day as the leading instrument. Heiland [10, 1926; 11, 1929] gives a detailed account of the theory of this instrument, and a simple derivation of the working equations is given by Lester [21, 1928].

In Fig. 10 is shown a cross-section through the Askania magnetometer for vertical and horizontal measurements.

The essential part of this instrument is the swinging system. It consists of a cubical metal block carrying two thin magnets (blades), adjusting screws, and a mirror. The whole system oscillates about a quartz knife-edge, resting on semi-cylindrical agate bearings.

For the measurement of the vertical magnetic intensity a horizontal balance is used, and for the horizontal magnetic intensity a vertical balance. The sensitivity of the instrument may be increased by approaching the centre of gravity of the swinging system to the fulcrum by means of the adjusting screws on the metal block.

Since the magnetic force along the earth's surface varies from place to place, the balance will be deflected one way or the other from a certain initial position determined at a base station. The deflexions are measured by means of an optical system. From the constant of the instrument and the amount of deflexion, the differences of the magnetic vertical or horizontal intensities with respect to a certain base station may be found. In different latitudes, or above large magnetic disturbances, the swinging systems may be brought back to their horizontal or vertical positions by auxiliary magnets, which may be placed below the instruments.

The horizontal magnetometer measures the horizontal magnetic intensity along the magnetic meridian. If the direction of the magnetic meridian varies between two stations, this variation is brought about by a horizontal force which is at an angle with the magnetic meridian. Of such a force only the component along the meridian is

measured by the horizontal magnetometer. In order to find the east-west component of the total horizontal variation, we have to measure the variation of the declination between the two stations.

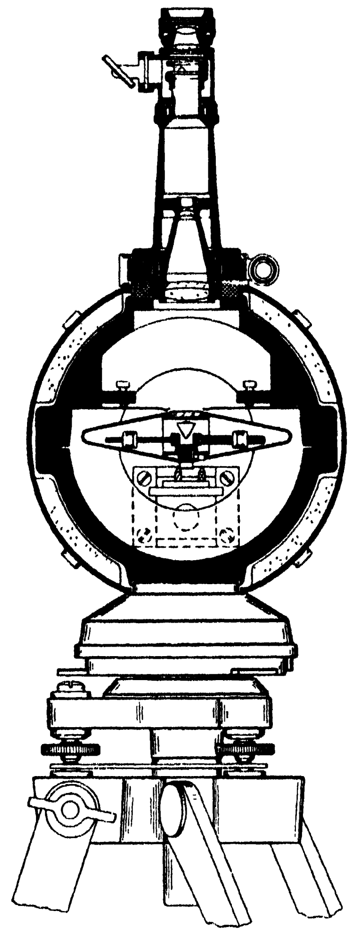

FIG. 10. Askania Magnetometer.

From Fig. 11, where

H_B = total horizontal force at base station,
H_{II} = total horizontal force at second station,
H_T = total horizontal variation (vector) between base station and second station,
H_M = horizontal component of H_T along magnetic meridian of second station,
H_D = horizontal component of H_T at right angles to meridian of the second station,
δ_D = angle between the two meridians, in radians.

then for small angles:

$$H_D = \delta_D \times H_B \quad \text{and} \quad \sqrt{(H_D^2+H_M^2)} = H_T;$$

if $H_B = 40{,}000$ gammas, $\delta_D = 10'$, or $\pi/1{,}080$ radians, then $H_D = 116$ gammas.[1]

Measurements of the declination are made by means of theodolites, which contain a very sensitive horizontal magnetic needle. The angles, α_1 and α_2 between the magnetic needle and the line connecting the two stations are measured at both stations. The variation of the declination is then found by the relation (Fig. 12):

$$\alpha_1+\alpha_2 = 180+\delta.$$

Field Procedure.

The magnetic stations may be arranged along profiles or in a network, according to the accessibility of the terrain, or the purposes of the survey. If only large magnetic anomalies are looked for, the field work is relatively simple and can be done speedily. Utmost care must be taken,

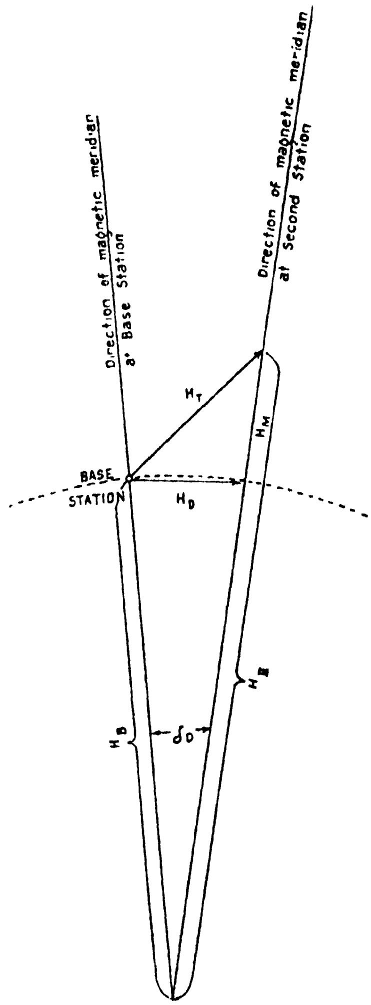

FIG. 11.

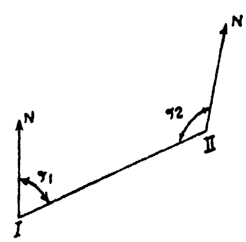

FIG. 12.

however, to locate small anomalies, ranging from 10 to 30 gammas, which have been found to indicate structures within the sedimentary column of the oil regions. Unfortunately, the observer is often under the spell of a large local or regional anomaly and neglects small variations of the magnetic intensity. Such minor variations may, however, prove to be of much more economical significance than the large anomalies, as is schematically explained in Fig. 13.

It is best first to cover the area under investigation by an equally spaced net of vertical intensity measurements and to supplement them later, if necessary, by typical profiles, along which all three magnetic elements are measured. For purely qualitative investigations the vertical intensity measurements will, as a rule, suffice; for quantitative investigations all three elements should be observed, if possible, over the whole area.

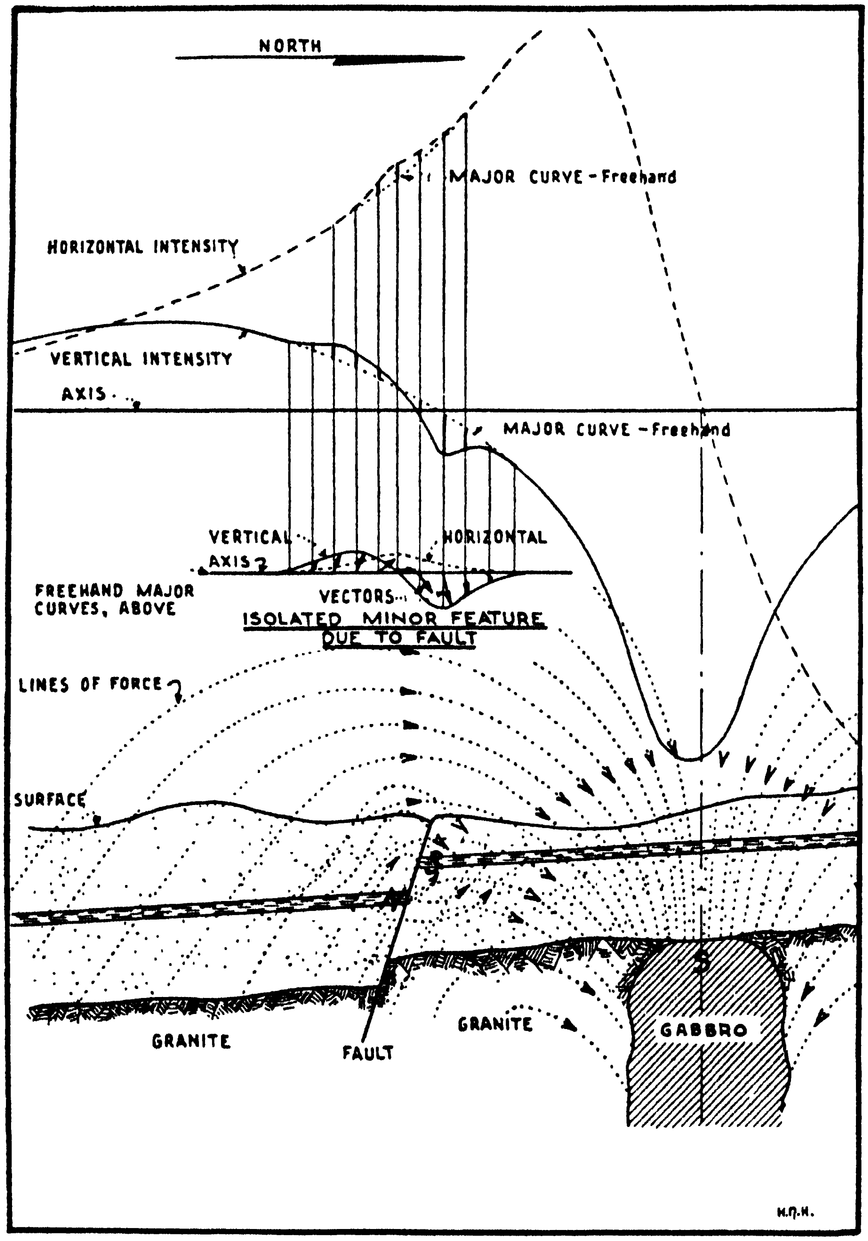

FIG. 13. Separation of local and intra-local magnetic anomalies. (After Lynton.)

To the field data a number of corrections must be applied:

(1) *Diurnal Variations.* The vertical magnetic intensity is subject to daily fluctuations. In the northern United States, for example, it is strongest at noon, when, in the southern States, it is weakest. The variation ranges from 10 to 30 gammas. The declination and the horizontal intensity are subject to similar fluctuations. Though the monthly average of these fluctuations is fairly constant, they may greatly vary from day to day, or, on the same day, from station to station. It is best to eliminate the daily variation by observing a number of stations repeatedly during the day.

(2) *Magnetic Storms.* Besides the periodic daily fluctuations, irregular and often sudden disturbances may affect the earth's magnetic field. They may amount to 300 gammas for the vertical intensity.

(3) *Normal Variation.* Due to the earth's magnetic field, there is a normal increase of the vertical intensity with latitude, which amounts for Texas to about 15 gammas per mile. Similar variations occur in the horizontal intensity and in the declination.

(4) *Temperature Variation.* In the latest type Askania instruments the influence of temperature variations upon the balance system has been eliminated for practical purposes. In the older type instruments it is corrected with the diurnal variation. For declination measurements it may be eliminated if two instruments are used simultaneously.

Magnetic Vector Method for the Representation and Interpretation of Magnetic Anomalies.

Deduct from the measured absolute values of the vertical and horizontal intensities and from the declination at a certain station the respective values of a 'normal' field. The differences between measured and 'normal' vertical intensities, south–north horizontal intensities, and west–east horizontal intensities may be represented by a magnetic vector in space [12, 1932]. The size and direction of this vector are dependent upon continental, regional, or local anomalies, all according to the definition of the 'normal' field.

Fig. 14 represents a cross-section through two anticlines separated by a syncline, and demonstrates schematically the paths of the magnetic lines of force and the local magnetic vectors as due to the local 'structures' only, after the 'normal' magnetic field of the earth has been eliminated. The total local vector is resolvable into two components —the local vertical and the local horizontal vector.

In order to determine the components for the vectors the local magnetic curves are smoothed to form terrestrial curves. The 'normal' values, as interpolated between the terrestrial curves, are then subtracted from the observed values at the respective stations. The differences represent the regional or local anomalies of the vertical and north–south horizontal intensity and of the east-west horizontal intensity.

For a clearer understanding, let it be assumed that the magnetic effects of the two anticlines and the syncline are

equivalent to the effects of two negative ($-P$) poles and one positive ($+P$) pole, as shown in Fig. 14.

Above the negative poles the local magnetic intensity is directed perpendicularly downward towards the poles (positive vector). Above the positive pole the magnetic intensity is directed perpendicularly upwards, away from the pole (negative vector). Along the surface, half-way between the positive and negative poles, the two vertical tendencies compensate each other and only a horizontal component remains, directed from the positive towards the negative pole (neutral vector). Between the vertical and horizontal directions of the intensity there occurs a gradual change, as shown in the diagram. As long as the vector is still directed downwards, it may be called a positive vector; if the direction is upwards, a negative vector.

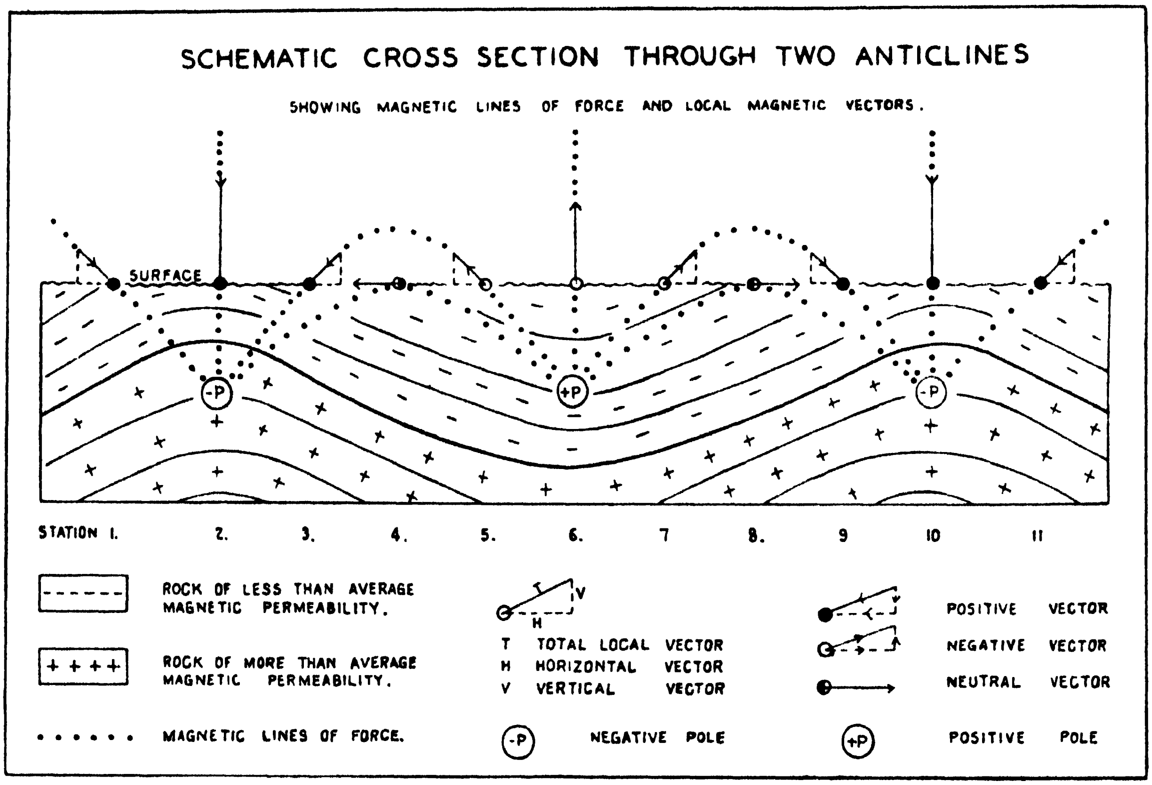

FIG. 14.

Magnetic Vector Maps.

The local magnetic vectors may be plotted at their respective stations on the maps in the shape of vector triangles, if each triangle shown in Fig. 14, is turned through 90° around its horizontal component, which is represented by the dashed lines beginning at the station point.

The representation of the anomalous magnetic local forces by vector triangles is of decided advantage, especially if the distance between stations is great, which is the case for most of the magnetic surveys made by the different States.

In the United States, in European and other countries, extensive absolute magnetic surveys have been made by the Surveys of the respective countries. The distance between the station points of these surveys varies from 10 to 50 miles.

Extensive studies of the anomalies of the vertical intensity, as revealed by these surveys, and their correlation with geology have been made [19, 1933; 24, 1927; 28, 1928–9]. But though a definite connexion between broad structural features and magnetic anomalies of the vertical intensity could be made, such studies could only incidentally yield any information about the more local or semi-regional type of structure, because the distances between the magnetic stations were far too large.

It is quite evident that two, three, and more magnetic 'highs' and 'lows' may occur between stations placed at such distances, and the lines of equal vertical magnetic intensity, drawn on the basis of such stations, as a rule veil, rather than set forth, smaller magnetic anomalies, which are of particular interest to the commercial geologist.

A study of Fig. 14 will make the previous statement clear. It might happen that stations 1 and 11 had been occupied by the State Survey. As both stations have the same magnetic vertical intensity, they lie on the same isogam which would pass over the entire structure without indicating any change. The same would happen if also stations 3 and 9 had been surveyed. Any other combination of the vertical intensity of two or three stations would give widely varying indications of some anomaly. Most of the 'structures' which create local anomalies, however, lie at depths ranging from 2,000 to 15,000 ft., and their magnetic effect is felt within a horizontal distance from the edge of a 'structure' of only about twice its depth. Therefore it is reasonable to assume that, within a distance of 10–50 miles, only one station is occupied, as a rule, on a particular 'structure', and there is little use to combine the measurements of the different stations unless broad structural features are suspected.

Contrary to the opinion of some magneticians, the writer holds that with such large distances between stations much more detailed information may be obtained by studying the horizontal intensity than by studying the vertical intensity, and thinks that this is confirmed by a study of the

horizontal intensities in Fig. 14, especially if it be realized that the anomalies are three-dimensional.

The best information is, of course, obtained by a combination of the horizontal and vertical intensities to form a magnetic vector in space. The magnetic anomaly at Grand Rapids, Michigan [16, 1934], offers an example for the vectorial representation of both local and regional magnetic anomalies.

The United States Coast and Geodetic Survey [8, 1925] has made observations of the magnetic elements at the county seats of the State of Michigan and also at seven auxiliary stations near Grand Rapids.

In studying this vector map, it should be considered that, as shown in Fig. 14, there exists somewhere along the prolongation of the horizontal vector either a magnetic 'high' or 'low', which corresponds to some kind of geological feature of structural or petrographical character.

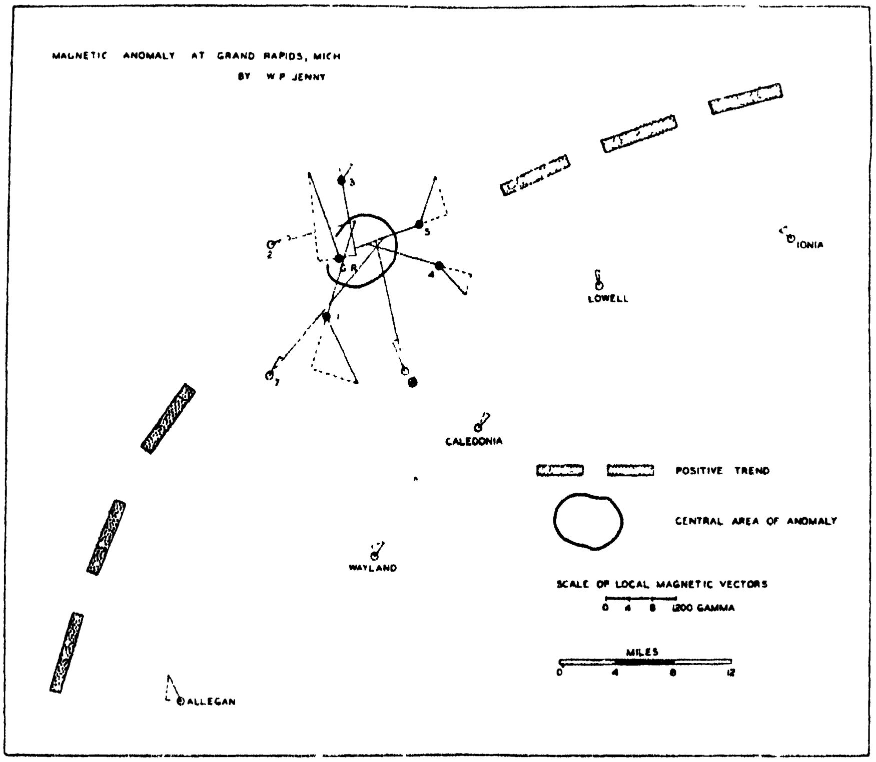

FIG. 15.

Due to the long distances between some of the stations, it is necessary to use the most probable geological interpretation. Though two, three, or more local 'highs' and 'lows' are possible between two neighbouring stations, it is probable that regional geological structures extend at right angles to the horizontal magnetic components, where the majority of the latter are nearly parallel to one another over a large area; or a common geological feature is probably responsible for a series of vectors if they are all directed towards or away from the same point.

The horizontal components of the negative vectors at Allegan, Wayland, Caledonia, Lowell, and Ionia are directed towards the west, north-west, and north, and thus indicate magnetic positive anomalies along a line of magnetic positive trend, as shown in the diagram. Along this regional trend occurs the large positive anomaly of Grand Rapids. The vectors at Grand Rapids and at the seven auxiliary stations all point towards a positive area with its centre slightly east of Grand Rapids. It seems safe to interpret this anomaly as a large domal uplift along a regional anti-clinal trend.

The vector maps assist in the first place in the investigation of regional magnetic anomalies. If the original data are of sufficient accuracy, valuable detailed information may, however, be gained from each individual vector.

It is to be regretted that the accuracy of the magnetic stations as observed by the Surveys of the respective States is not always adequate to our purposes, as is seen, for example, from a comparison of the local vectors along the Gulf Coast [12, 1932] with the magnetometer map of this area [17, 1934], or of the regional magnetic map for southern Bavaria [1, 1934] with the respective vectors [14, 1933], which are based on Nippoldt's data [24, 1927].

Experimental Interpretation of Magnetic Anomalies.

The representation of the anomalous magnetic local forces by vector triangles is also of decided advantage for interpretation purposes.

If magnetic interpretations are made by the methods of Nippoldt or Haalk, there are three main reasons which explain the additional difficulties encountered in the interpretation of magnetic anomalies as compared with the interpretation of gravimetric anomalies.

In the first place, the induced magnetic field is so highly dependent upon the angle between the strike of the magnetically active structure and the direction of the inducing field that the same structure, according to its strike or geographical location, may yield entirely different magnetic anomalies (Figs. 7, 8); secondly, the specific gravity of rocks may be determined with a much higher degree of accuracy than their magnetic susceptibility; thirdly, the assumption of homogeneous magnetization applies only to bodies limited by surfaces of the second degree.

But since, in contradistinction to the gravitational field, the magnetic field may be surveyed by relatively simple means in three dimensions, the above-mentioned drawbacks are largely counterbalanced. This circumstance has not yet been taken into due consideration.

In the case of homogeneous masses the *size* of the magnetic vector in space is proportional to the *susceptibility* of a given mass, whereas the *direction* of the vector is dependent upon the *shape* of such a given mass [7, 1934; 23, 1930].

This point leads to results of considerable importance for the geological interpretation of magnetic anomalies, because it is possible to determine by relatively simple experiments the relationship between the direction of the magnetic vectors in space and the shape of a magnetically active structure.

Interpretation for Vertical Direction of Inducing Field. Regional magnetic anomalies will in many instances be the

result of the tectonics of the 'Basement' complex, which may be compared with an extended magnetic plate of large thickness supposedly cut into a series of vertical magnetic columns, or bar-magnets. These in turn may be displaced vertically so as to imitate tectonic dislocations of the Basement, such as anticlines, synclines, faults, grabens, &c.; it is possible thus to examine the influence of such tectonic features upon the direction in space of the respective vectors. In reality the problem will mostly be just reversed, i.e. the direction of the magnetic vectors will be determined through measurements in the field, and the tectonics of the underground deduced from the direction of these vectors.

Fig. 16 represents a cross-section through an apparatus indicating the qualitative and quantitative interpretation of magnetic anomalies, if the direction of the inducing earth's magnetic field is assumed to be vertical.

The vertical bar-magnets, representing segments of the 'Basement', for example, are first set to scale at the normal depth of the 'Basement'. The 'normal' effect thus produced upon the dip-needles is compensated by counter-weights on the negative side of the freely suspended needles, so that they are all horizontal. The bar-magnets are next displaced along the vertical until the various dip-needles assume the direction in space as before measured in the field and indicated by the respective pointers below the needles. The depth to the poles may then be read from the ribbons by which the bar-magnets are suspended. By connecting the depth readings of the individual poles, contour lines may be constructed on the looked-for structure, which is represented by an anticline in the figure.

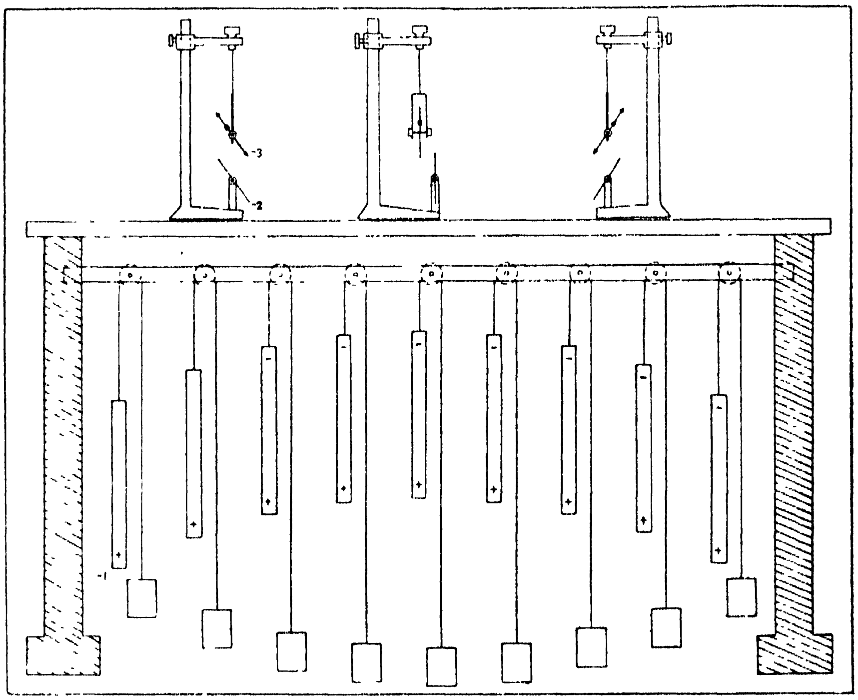

FIG. 16. Apparatus for the experimental interpretation of magnetic anomalies for vertical direction of inducing field.

1. Bar-magnets representing, for example, segments of the 'Basement' complex. 2. Indices, giving the direction of the anomalous local magnetic force as measured in the field. 3. Dip-needles, assuming the direction of the respective indices, after the bar-magnets are adjusted to represent local structure.

Interpretation for Optional Direction of Inducing Field. In practice the interpretation of magnetic anomalies is quite complicated, first, because the direction of the earth's magnetic field differs from the vertical, as was assumed for the inducing field of Fig. 16, to an extent depending on the latitude, and secondly, because there usually exists above the 'Basement' complex a series of layers with varying magnetic susceptibilities.

An artificial magnetic field approaching the actual conditions may be created by placing the apparatus within an electrically induced magnetic field with its axis parallel to the earth's magnetic field.

The determinations of the absolute magnetic susceptibility of the different layers above the 'Basement' complex offers great difficulties, but it is relatively easy to estimate their relative susceptibilities. The direction of the local magnetic vector is alone determined, so that it is sufficient to know the relative susceptibilities. Such a method has advantages over other methods which aim at the geological interpretation of magnetic anomalies on the basis of relative vertical or horizontal intensity measurements.

In Fig. 17 the bar-magnets are replaced by more or less continuous layers of a plastic material which has been mixed with iron particles, in proportion to the relative magnetic susceptibility of the respective layers in the stratigraphic column of the area under investigation. The layers have been cut into segments, which may be displaced in a vertical direction. The apparatus is placed within the homogeneous field of a large coil, as indicated in the figure. The direction of the induced field is parallel to the earth's magnetic field of the respective area.

First, all the layer-segments are placed to scale at normal depth, and the 'normal' influence of the horizontal layers and of the artificial homogeneous field upon the dip-needles is compensated. Next the layer-segments are individually raised or lowered until the dip-needles all assume the directions in space as measured before in the field and indicated by their respective indices.

This experimental interpretation takes into due account the inhomogeneous magnetization of a structure and the polarizing effects produced by the various directions of the earth's magnetic field.

These models have been devised as an aid to the solution of problems encountered in structural geology, but they may prove of value in some mining problems.

Practical Examples

Garber and Oklahoma City Fields.

As examples of magnetometer work in the oil regions of the United States there are shown the magnetic profiles and geologic cross-sections for the Garber field (Garfield Co.) and the Oklahoma City field (Oklahoma Co.), both in the State of Oklahoma.

Both structures lie along the southern extension of the

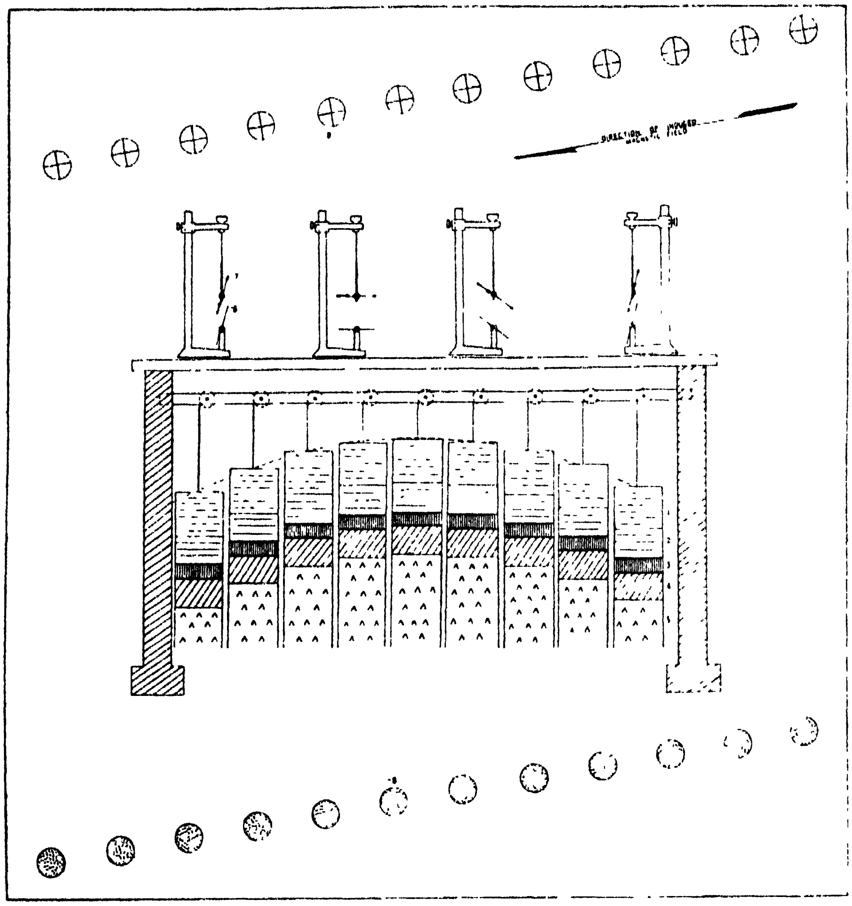

FIG. 17. Apparatus for the experimental interpretation of magnetic anomalies for optional directions of the inducing field.

1–5. Layers of plastic material mixed with iron particles in proportion to the relative magnetic susceptibilities of the represented subsurface layers. 6. Indices, giving the direction of the anomalous local magnetic force as measured in the field. 7. Dip-needles, assuming the direction of respective indices, if layer-segments are adjusted to represent local structure. 8. Coil for the induction of the artificial inducing field.

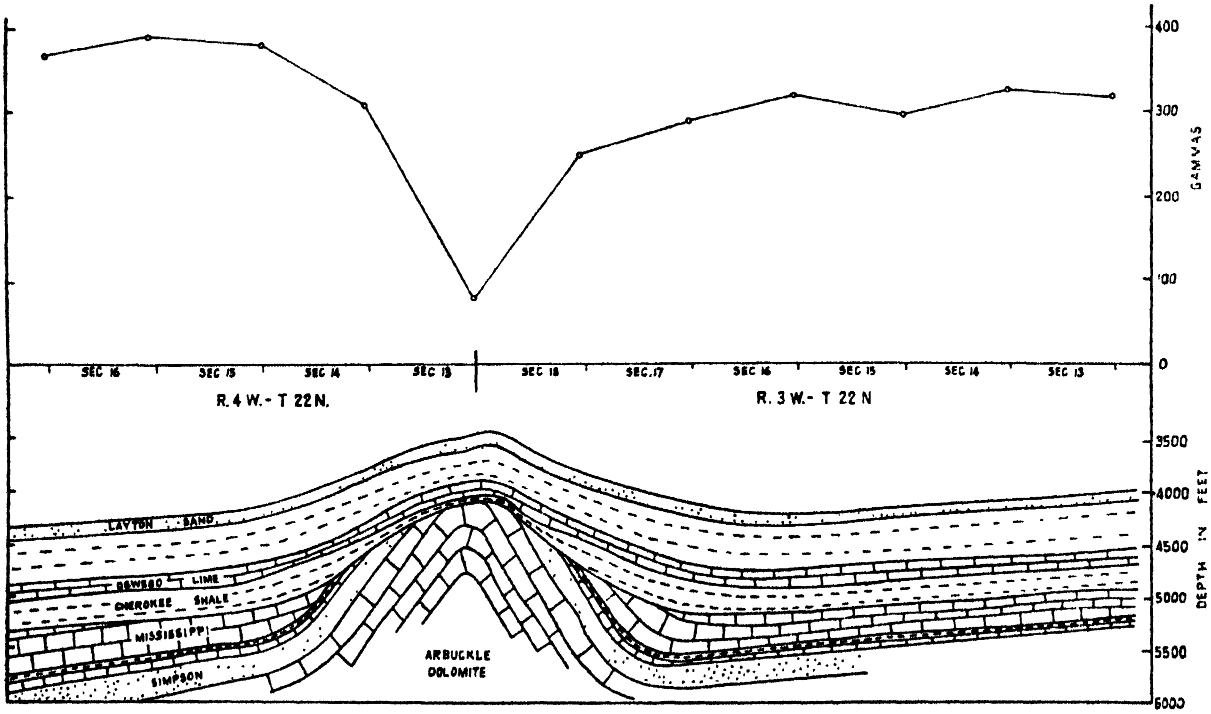

FIG. 18. Profile of vertical magnetic intensity and geological cross-section across the Garber field. (After Spraragen.)

Nemaha granite ridge, which extends in a south-south-westerly direction across the State of Kansas. Results of deep tests in the Garber field have indicated a relatively thin section (1,250 ft.) of Arbuckle limestone on top of the pre-Cambrian granite, and similar conditions may also be assumed for the Oklahoma City structure.

In both anticlines the Arbuckle Dolomite has been uplifted by about 2,000 ft. The east flank of the Oklahoma City structure is cut off by a fault with a throw of about 1,800 ft.

Hobbs Field.

The next example is the Hobbs field, Lea County, New Mexico. In Fig. 20 are shown the magnetic isogams and the contours drawn on top of the 'Brown Lime'.

The Hobbs anticline has a north-westerly direction and about 250 ft. of uplift. The stratigraphical section is composed of Tertiary sands capped by Caliche (200 ft.), Triassic, and Permian Red-beds (1,300 ft.), Potash-bearing salt

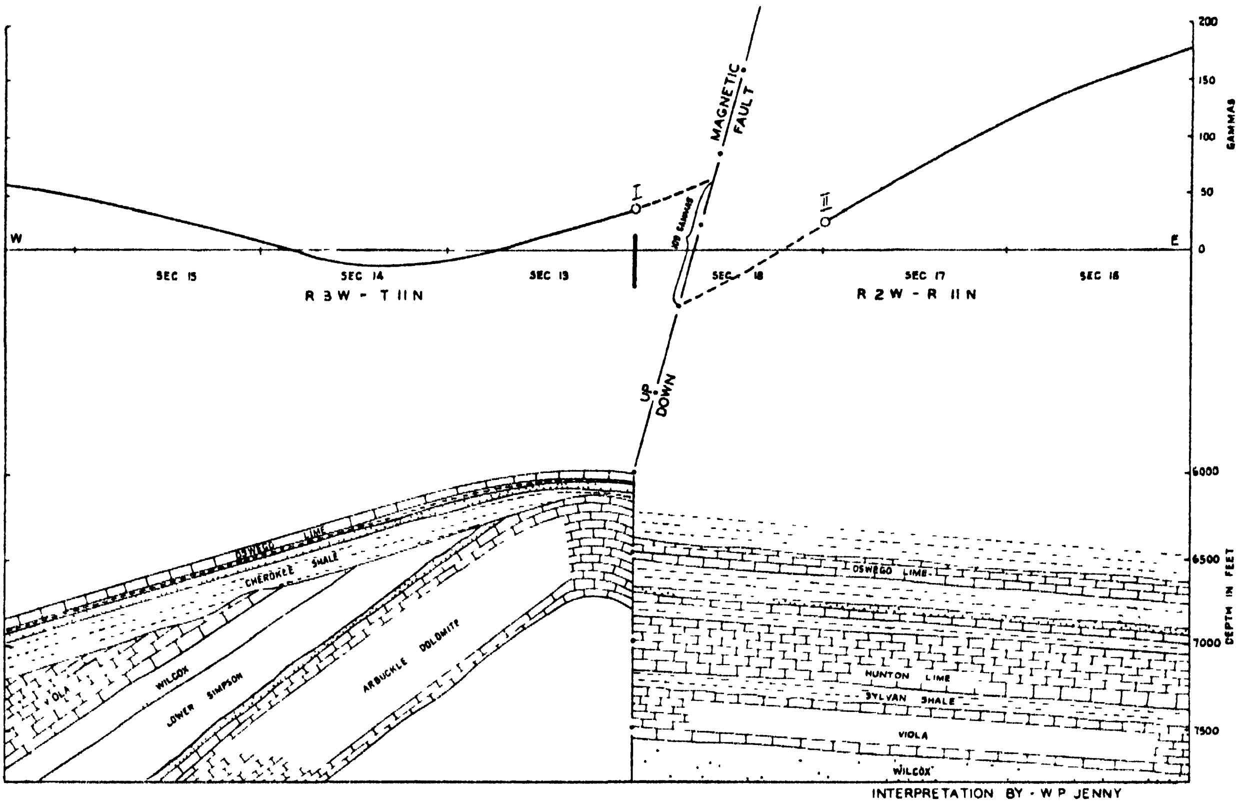

FIG. 19. Profile of vertical magnetic intensity and geological cross-section across the Oklahoma City field. (Magnetic data from Clifford's map, geological cross-section after Charles.)

The magnetic survey of the Oklahoma City structure was made before the development of the field [3, 1932]. The survey of the Garber structure [28, 1928–9] was made after development of the field, and therefore the minimum reading might be about 50 gammas lower than that which would correspond to the structure.

The striking feature of the magnetic profiles is that both structures show up as most decided magnetic 'lows'.

These 'lows' could be explained by the assumption that the granite protrudes through stronger magnetic schists.

Inasmuch as the thick Arbuckle Dolomite, which may be assumed as practically non-magnetic, is normally overlain in the area of the two structures by about 6,000 ft. and 8,000 ft., respectively, of partly highly ferruginous shales and sandstones, the writer ventures to suggest that the Arbuckle anticlines, piercing into and displacing higher magnetic shales and sandstones, might be the reason for these magnetic 'lows'. This suggestion is supported to some extent by the magnetic fault to the east of the Oklahoma City structure, since the higher reading at station 1 seems to indicate that a relatively shallow magnetic horizon has been uplifted on the upthrown side of the fault.

(1,400 ft.), Anhydrite with limestone, sand, and shale (1,200 ft.) underlaid by the producing horizon, the 'White Lime'. The 'Basement' is vaguely assumed to lie at about 10,000 ft.

The fold is magnetically indicated by a pronounced 'maximum' in the south-westerly part and a 'minimum' in the north-westerly part. The writer is inclined to interpret these features as due to the induced polarity in a deep anticlinal ridge, which lies essentially below the producing structure. The small uplift in the shallower beds probably does not materially affect the magnetic picture.

Yoast Field.

The above three magnetic anomalies are very pronounced and amount to several hundred gammas. Minor structural features produce, as a rule, much smaller anomalies, of which an example is given by the magnetic survey of serpentine mass at Yoast field, Bastrop County, Texas (Fig. 21).

Inasmuch as the centre of the 'high' of the vertical intensity anomaly occurs over the fault near the highest

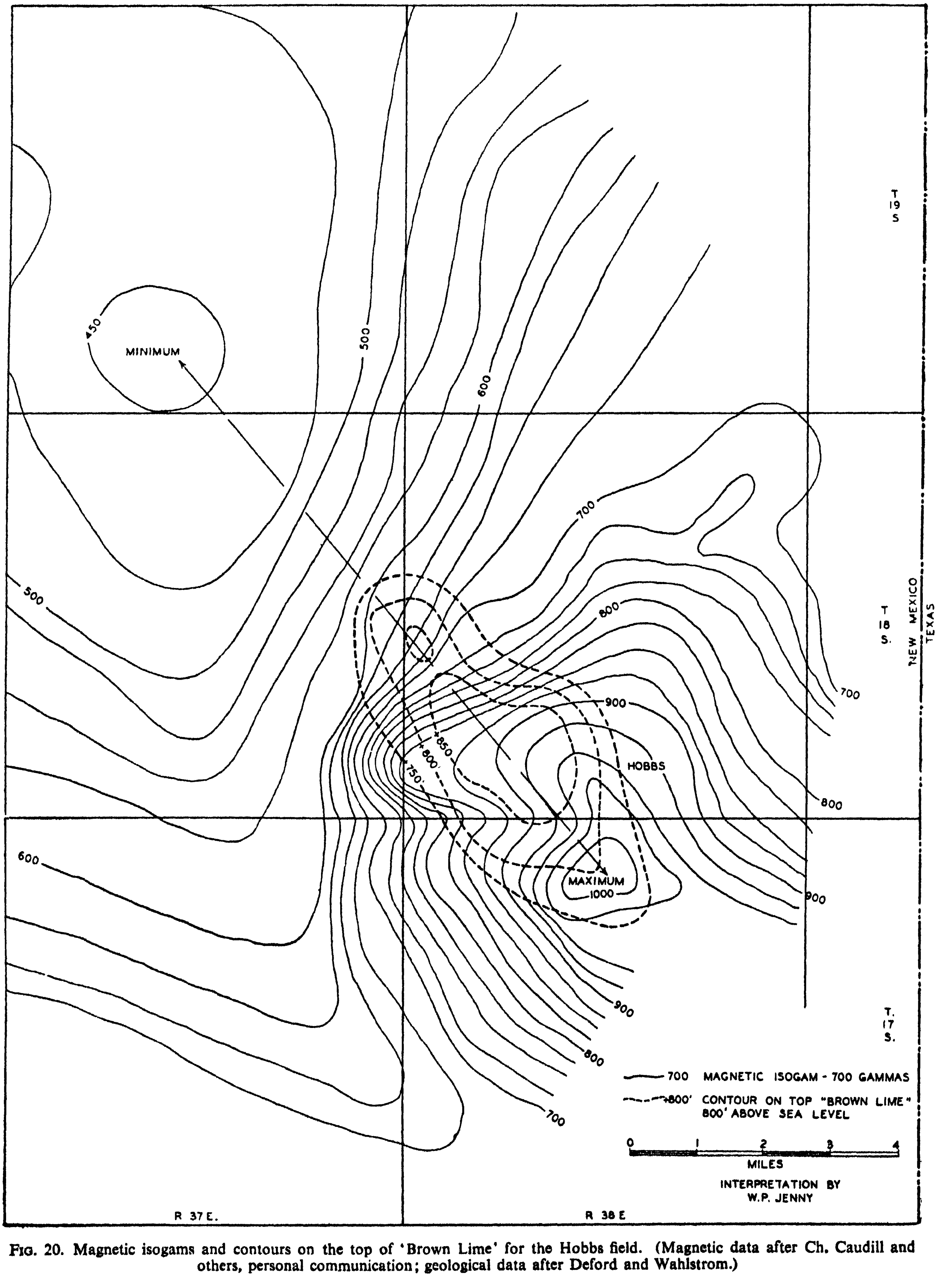

FIG. 20. Magnetic isogams and contours on the top of 'Brown Lime' for the Hobbs field. (Magnetic data after Ch. Caudill and others, personal communication; geological data after Deford and Wahlstrom.)

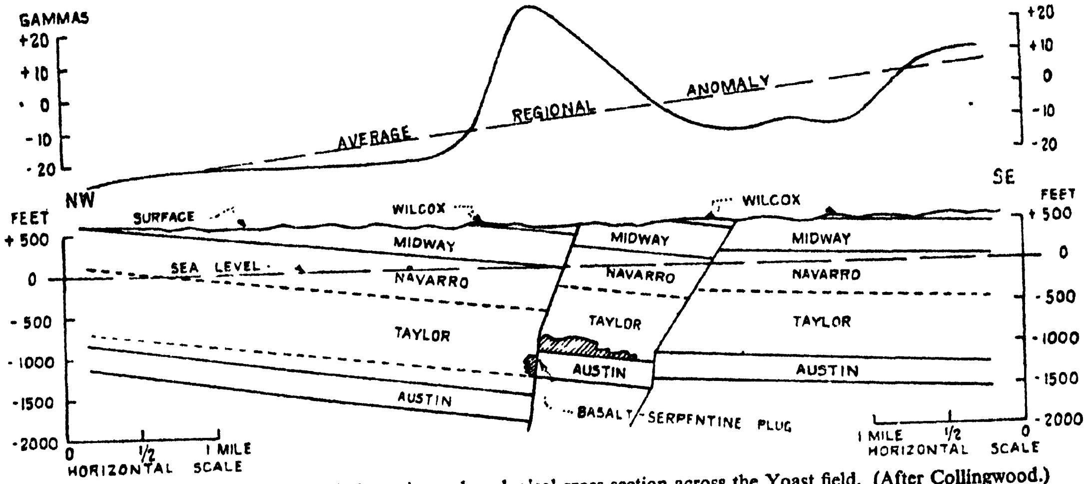

FIG. 21. Profile of vertical magnetic intensity and geological cross-section across the Yoast field. (After Collingwood.)

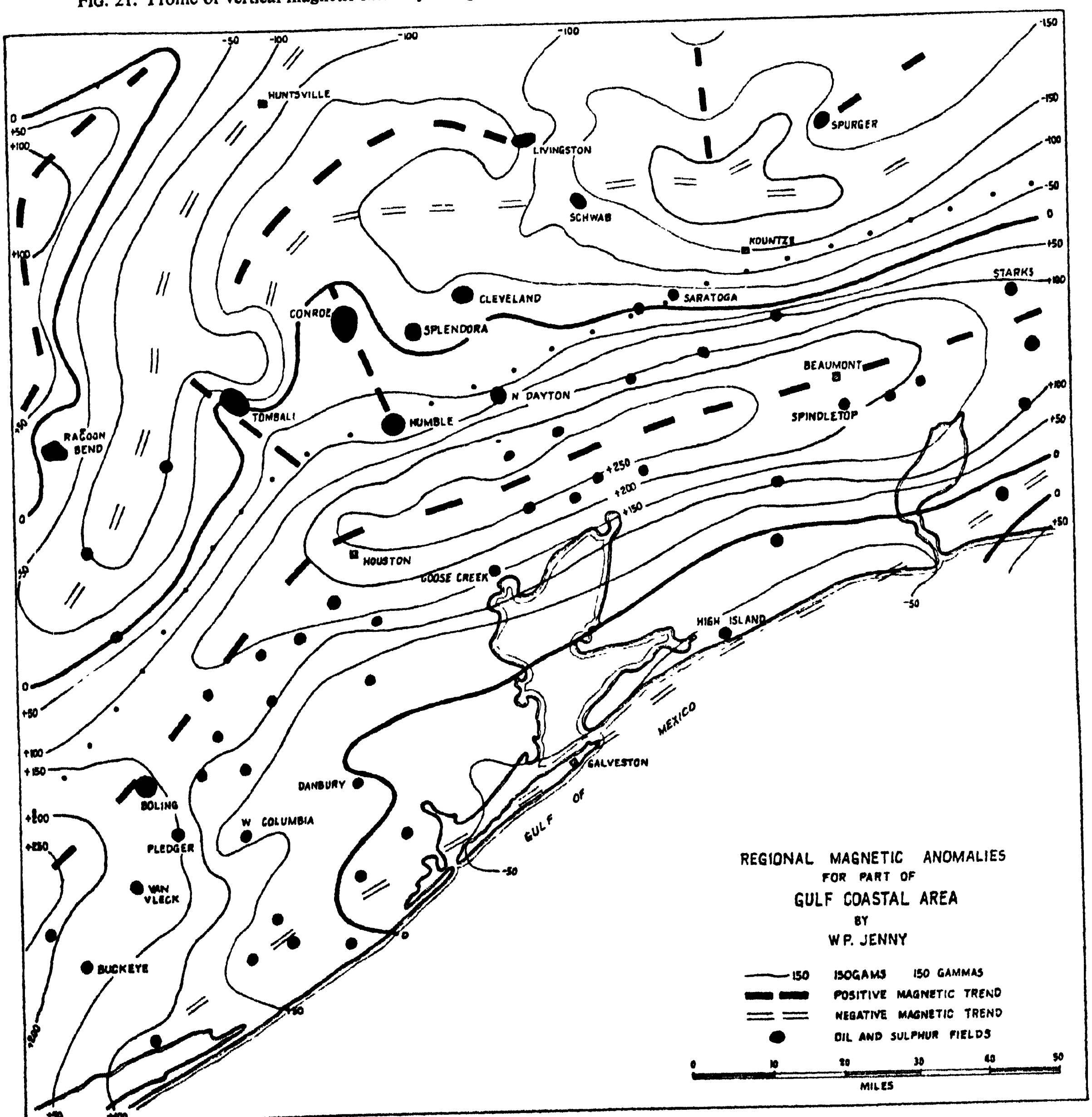

FIG. 22.

part of the mushroom top of the serpentine mass, Collingwood [4, 1930] infers that this high anomaly is due to a small neck or vent fillings of igneous rocks in the fault plane, below the top of the Austin chalk.

Regional Map for Part of Gulf Coastal Area.

Fig. 22 represents the regional magnetic anomalies for part of the Gulf Coastal area of Texas, in the general neighbourhood of Houston.

The writer [17, 1934] is inclined to interpret the magnetic positive trend, to the south of the dotted line, as due to a thickening of the highly ferruginous sediments of Eocene and younger age, and the magnetic negative trend through Galveston as due to a thinning of these sediments. Thus the magnetic 'high' between Houston and Beaumont would indicate a basin, and the magnetic low trend at Galveston an anticlinal trend in the deeper Gulf Coastal strata. The depth to the 'Basement' is estimated at from 20,000 to 30,000 ft.

To the north of the dotted line, magnetic high trends seem to represent anticlinal, and magnetic low trends synclinal structures.

The main fields, Conroe, Tomball, Livingston, and Spurger, lie along magnetic high trends. It is interesting to note that these fields are gravimetric minima. This might indicate that they are deeply buried salt-domes along anticlinal structural axes. On the other hand, a large number of tests drilled on gravimetric minima which lie along magnetic low trends, for example, along the region which extends from a point west of Conroe towards the Schwab area, were found to be structurally normal. In these cases the gravimetric minima were probably not produced by a salt uplift, but by the magnetically indicated syncline.

The position of the dotted line has been determined on the strength of magnetic and stratigraphic data. Along this line a sharp flexure in the deeper strata is presumed by the writer.

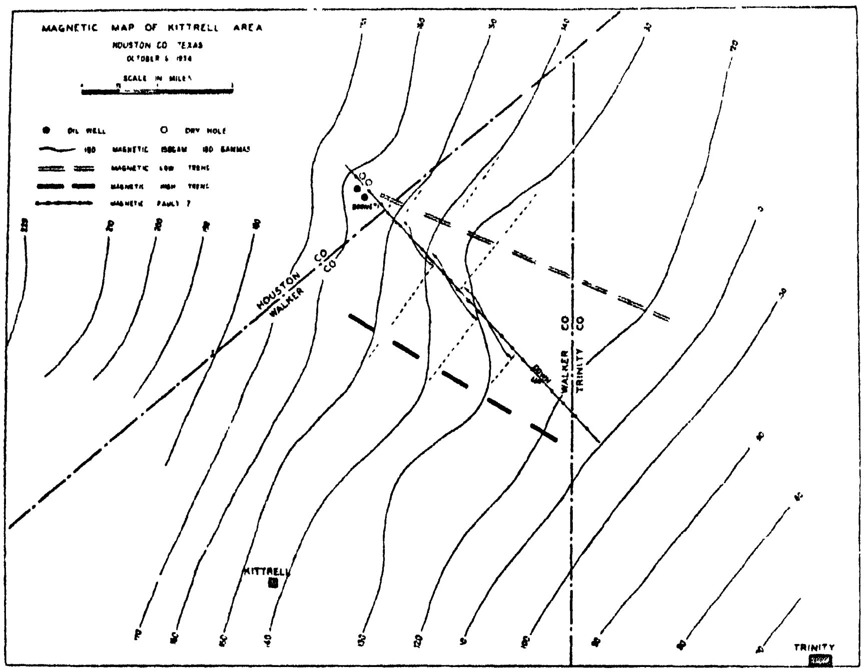

FIG. 23.

Kittrell Field.

Like other geophysical methods, the magnetic method does not always yield results as definite as the examples shown above. A structure of appreciable size seldom fails to produce a magnetic anomaly of at least 10 to 20 gammas, yet such anomalies may not always be readily interpreted in terms of structure. As an example, the magnetic diagram of the newly discovered Kittrell field is here given (Fig. 23). The field lies in south-western Houston County, Texas, about 25 miles north of Huntsville, and consists so far of two producers and a number of dry holes.

There is a uniform increase of the magnetic intensity from the town of Trinity towards the north-west. Two miles to the south-east of the discovery well Boone No. 1, the equal spacing of the isogams is interrupted. A magnetic 'low' is developed between the 130 and 120 isogams. The axis of this 'low' trends towards the discovery well. About 2 miles south a parallel high trend seems to be indicated. These two trends were tentatively interpreted in the early stage of the field as indicative of a cross-dip fault, as shown in the diagram. Further drilling did not prove or disprove this suggestion. The fact that until now little oil has been found, and only in the north-western, i.e. updip, areas of the supposed fault would rather be in favour of this theory, since such a cross-dip fault might be a poor trap for oil. The magnetic diagram could, however, be explained in many different ways. The only conclusion that seems to result fairly definitely from the magnetic survey is the probability of some structural feature to the south-east of the discovery well.

Such vague information may not be significant enough for the location of wells, but it might be of some importance in an economical plan for reflection seismograph and torsion-balance surveys, especially where the time element plays an important role.

Micromagnetic and Gravimetric Profile through a Gulf Coastal Prospect.

Clear evidence of the importance of magnetic prospecting along the Gulf Coast is given in Fig. 24.

A gravimetric minimum between stations 4 and 5 is indicated by a southern tendency of gradients 1 to 4 and by a northern tendency of gradients 5 to 7. Between 7 and 8 a marked reversal takes place.

Between these two stations also the micromagnetic profile indicates clearly a sudden break, which must be interpreted as a fault. The top of the magnetically indicated structure coincides well with the area of the torsion-balance minimum. Thus the corroborative structural evidence furnished by the two methods strongly supports the conclusions, which may be drawn from the results of each method by itself.

The total magnetic anomaly along the above profile amounts to 10 gammas. The term 'micromagnetics' is

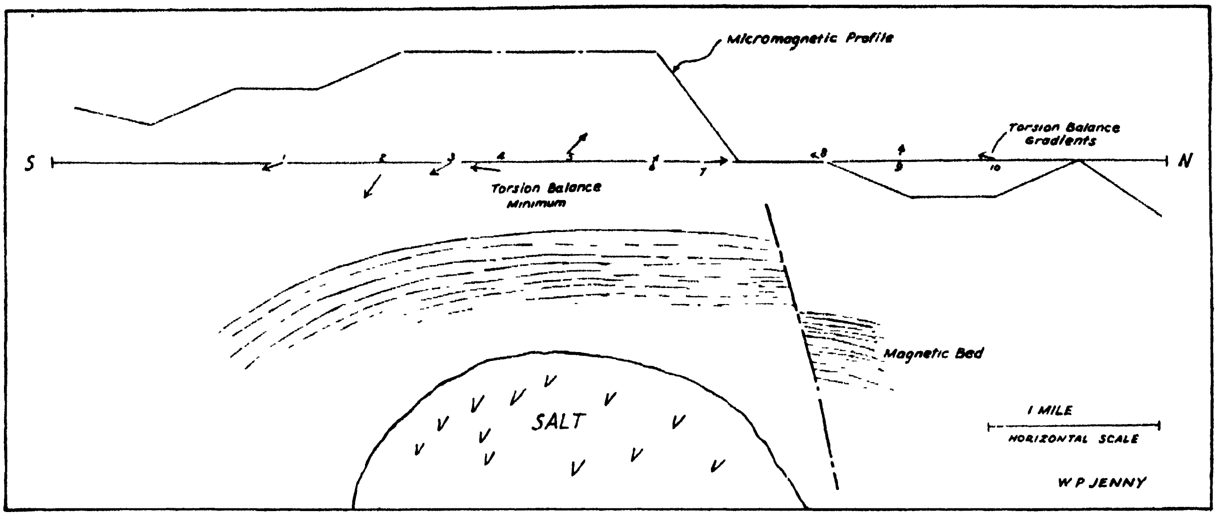

FIG. 24 Micromagnetic and torsion balance profile through a Gulf Coastal Prospect.

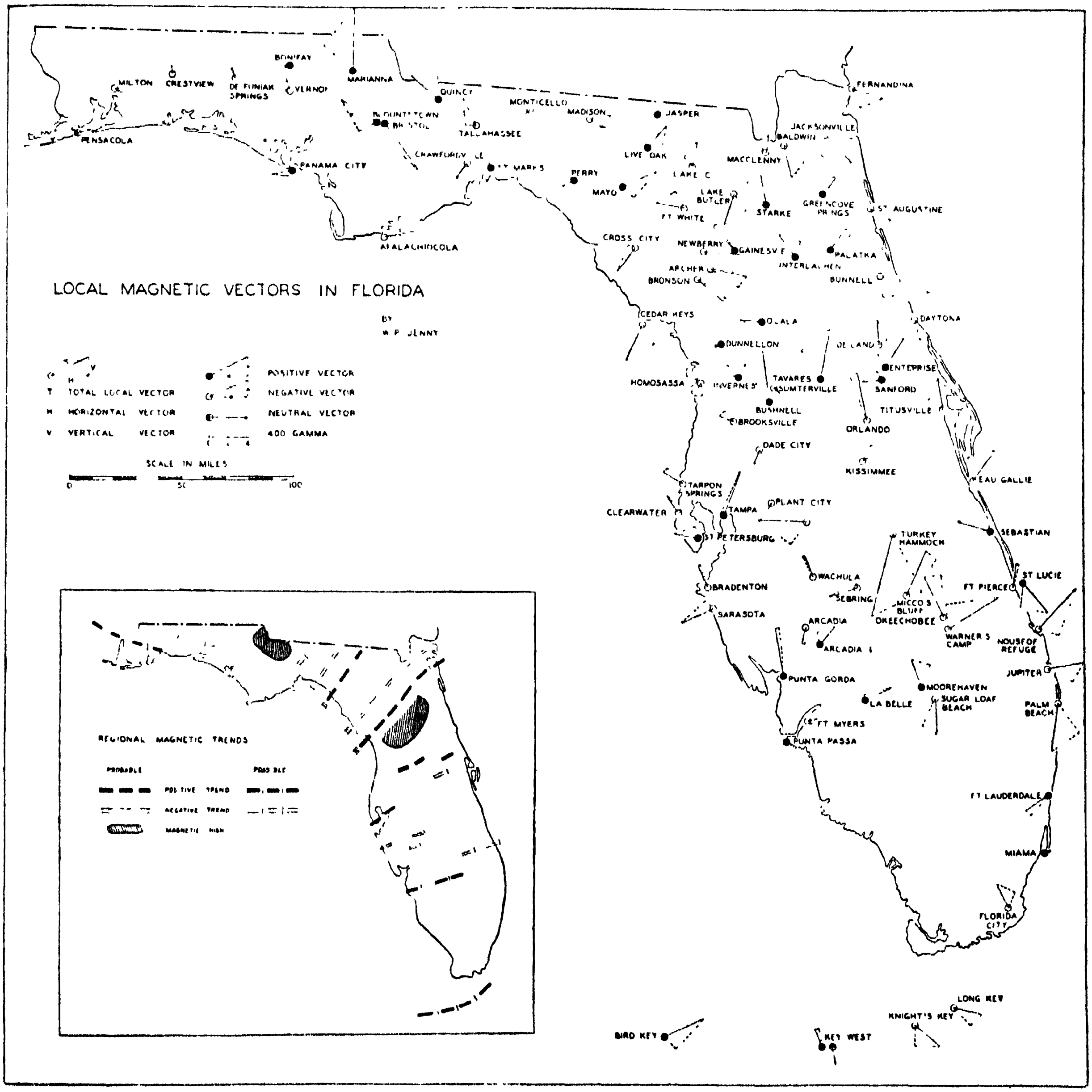

FIG. 25.

therefore suggested in order to contrast the extremely accurate recent magnetic work with the less accurate surveys of former years.

From the small horizontal extent of the magnetic and gravimetric anomaly above the fault there results conclusively that the source for both the magnetic and gravimetric anomaly must lie at relatively shallow depths.

Vector Map of Florida.

Interpretation of the vector map of Florida according to the principles explained before (p. 343), shows that these magnetic vectors indicate a number of deep structures [18, 1934], which are shown as regional magnetic trends on the inset of Fig. 25.

In the central part of Florida the main direction of the horizontal components of the vectors is north-west to south-east, which indicate regional structures with a north-east to south-westerly direction.

In southern Florida the main direction of the horizontal components is about north–south, which suggests regional structures with an east-westerly direction.

The generally assumed tectonics of this area suggest that these magnetic trends are caused by block-faults; however, taking into due consideration both the intensity and the direction of the vectors, it appears more reasonable to interpret the positive trends as anticlinal structural axes of the 'Basement' and possibly also of the overlying strata, and the negative trends as synclinal structural axes.

Since the direction of the northern trends shows a striking parallelism with the Appalachians, they probably represent structures connected with the Appalachian orogeny.

In southern Florida no continuous structural trends can be observed, but a number of parallel east-westerly anticlinal and synclinal trends of various length and intensity are possible, as indicated on the inset.

From the vector study it would therefore seem that early folding under that area of the peninsula as far south as Ocala, contrary to general opinion, was parallel to the Appalachians, trending north-east by south-west. From Ocala or south the province seems to change in type from the Appalachian to the Antillian.

The study of magnetic vectors suggests that, contrary to general opinion, the early folding under southern Florida as far south as Ocala was parallel to the Appalachians, north-east to south-west.

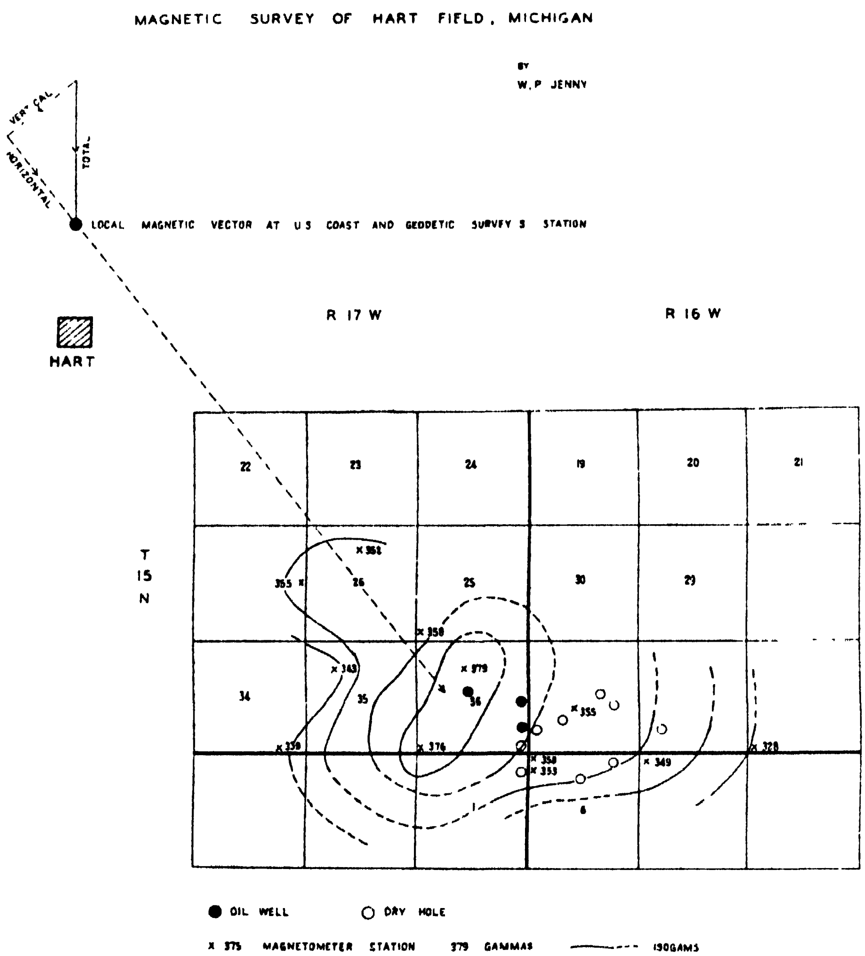

Fig. 26.

Survey of Hart Field.

A final example of the use of magnetic vectors is taken from a study of the recently discovered Hart field, Oceana County, Michigan [16, 1934].

The direction of the local magnetic force as indicated by the vector at Hart suggests a magnetic 'high' to the south-east, which might correspond to an uplift with a possible north-east to south-westerly axis. A short magnetic survey of the area (Fig. 26) has fully confirmed this suggestion.

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NOTE

[1] The unit of magnetic force, or intensity, is a force of one dyne acting on unit pole. This unit is 100,000 times as large as a gamma.

ELECTRICAL PROSPECTING FOR OIL

By the late C. SCHLUMBERGER, M.Inst.P.T.

INTRODUCTION

ELECTRICAL methods, when first used, appeared especially suitable for prospecting metallic ores. Actually they have become more and more used for the geological prospecting of the great sedimentary basins, and, as a consequence, of oilfields. Present-day electrical methods are often better suited to the study of deep and wide structures, even if the resistivities of the formations in question do not differ widely, than to the investigation of mineral deposits, whose form is frequently unexpected, and whose total volume is always very small compared with that of the surrounding rocks.

Metallic ores sometimes give rise to specific electrical reactions (spontaneous polarization) [3, 1920] by which they may be recognized, whereas the characteristic properties of oil have as yet played no part in its detection. In particular, the high resistivity of oil sands cannot be used as a basis of diagnosis, because this property is concealed by the great conductivity of the surrounding beds, generally rich in salt, and much thicker than the oil layers. It is only when local measurements are made inside drill-holes that the high resistivity of the oil can be used to discover petroliferous beds (see article on Electrical Coring). To sum up, the electrical prospecting of an oil region amounts simply to the geological study of a structure, as is the case with other geophysical methods. The salinity of the formations, also, may easily be determined electrically. This fact is to the advantage of electrical methods, as experience has shown that saline formations are a condition almost necessary for the presence of oil.

Numerous electrical methods are now in common use for oil prospecting. They may be grouped into two classes, according to the nature of the measurements:

I. **Electric Field.** Determination, at the surface, of the potential difference set up between two elecrodes by direct or alternating current passing conductively through the soil between another pair of ground electrodes. At the present time, these studies are carried out chiefly by the resistivity method, with its two applications, the Resistivity Map and the Electrical Sounding, in which the earth resistivity is measured.

II. **Magnetic Field.** Determination of the magnetic vector created by alternating current, sent either conductively into the ground, or applied inductively by means of a horizontal loop.

The present article will be devoted in particular to the resistivity method, and only a brief outline of the electromagnetic methods will be given. Other processes, such as the 'Equipotential Map' and the 'Potential Drop' methods, will not be described, as they have not been, as yet, widely applied to oil prospecting, and are similar in many respects to the resistivity method.

To avoid confusion, it should be mentioned that prospecting for oil *inside* a drill-hole is described in detail in the article on Electrical Coring (p. 352).

RESISTIVITY METHOD

Resistivity of the Rocks [4, 1931] (see also on this subject the article on Electrical Coring). Nearly all the electrical methods are based on the differences of resistivity existing in the various rocks. Rocks are conductive only on account of the water impregnating them, and the resistivities are inversely proportional to the total quantity of salt dissolved in this water, per unit volume of rock. As petroliferous formations are generally very saline, they are also very conductive, and this is immediately noticeable in electrical prospecting for oil. There is, however, one exception to this rule, that of petroliferous limestones, which may be very resistive on account of the salt-water which is collected together in fissures and does not impregnate the general mass of the formation. As an example, the resistivities, expressed in ohms per cubic metre, of the formations encountered in the Roumanian oilfields are given:

Quaternary Terrace	75 200 ohm-metre
Levantine (succession of shales and sands)	15–50 ,, (average 20)
Dacic (sandy shales)	8–10 ohm-metre
Pontic (shales) . .	2–3 ,,
Meotic	3 ,,
Limestone	100 1,000 ,,

The first question which arises is the extent to which resistivity is a characteristic coefficient of a given formation. One point to be considered is the influence of the temperature, an increase of which results in a decrease of resistivity. As a rule, this influence does not constitute a serious inconvenience in a survey conducted from the surface of the ground. The effect of the permeability, on the other hand, must not be overlooked. Impervious rocks contain approximately the same amount of water throughout, and this water, which is firmly held in place by capillarity, possesses almost the same chemical composition everywhere. The resistivity, depending on this absorbed water, keeps a constant value over a wide area, and constitutes a specific and reliable parameter of such rocks. If we now consider a very permeable formation such as, for instance, a sand, the percentage of water contained therein will depend on its position with respect to the water-level. The water itself will have a varying composition: pure rainwater in some places, water more or less rich in dissolved salts in others. The resistivity of a permeable layer, therefore, is not always a reliable indication of its lithological nature.

The measurements of resistivity under discussion will always involve very large volumes of ground, and consequently represent average values. Under these conditions, regular figures are obtained and the measurements have a geological significance, avoiding local singularities. It should also be observed that the sedimentary rocks are more conductive parallel to their strata than perpendicular thereto; the ratio between these two conductivities frequently reaches 1·5 or even 2. This anisotropy [2, 1932, 1934] sometimes constitutes a serious complication, but may, however, be used to estimate the dip of the strata.

Measurement of the Ground Resistivity. The quadripole technique, first described by Wenner in 1916, is generally used to determine the ground resistivity. Its principle is quite simple. Between two ground electrodes A and B set up at the surface of the soil, an electric current i is sent into the ground by a battery S (Fig. 1). The flow of this current

creates, by ohmic effect, a potential drop ΔV between two measuring electrodes M and N placed at the surface, generally between A and B. This drop is measured by a potentiometer P. From the known values of i and ΔV, it is easy, by a simple formula, to compute the resistivity of the ground, the latter being supposed homogeneous and horizontal in the entire volume taken in by the measurement. Since the ground generally does not fulfil these conditions, and is more or less heterogeneous, the value given by the formula does not correspond to the actual resistivity of a given rock, but to an average resistivity of the various rocks included in the measurement. This average is called the 'apparent resistivity' of the ground between M and N.

Let us discuss more accurately the concept of the volume taken in by the measurements. It is obvious that the parts of the ground nearest to the measuring-device play the most important role, whilst those situated at some distance from the instrument do not have any appreciable effect on the result. In any case, the law of decrease with distance is very complicated. It cannot be expressed in an exact mathematical formula, and we must, therefore, be satisfied with approximations. We give herewith the simplest. Let us suppose that the measuring-device be such that M and N are situated on the line AB, and on either side of its centre. As may be seen in Fig. 1, it is almost as though all the lines of current going from A to B were concentrated

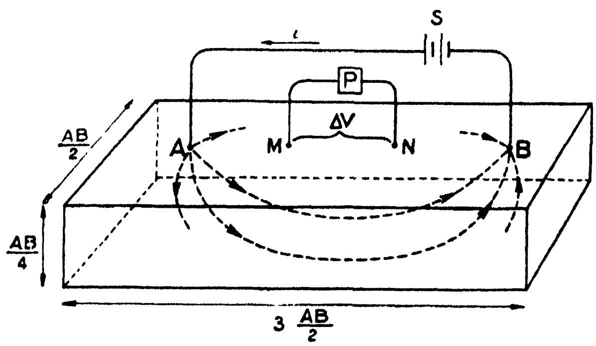

FIG. 1.

inside of a parallelepiped, possessing a width of $AB/2$, a depth of $AB/4$, and a length of $3AB/2$. At the centre, where the ohmic drop is measured, the lines of current are approximately parallel to AB. The volume taken in by the measurement is the parallelepiped. The ground outside of this volume does not play an important part. The thickness $AB/4$ of the parallelepiped is often called the 'investigation-depth' of the measuring-device. Although this scheme only gives a rough idea of the facts, it serves, nevertheless, to clarify the following essential considerations.

Resistivity Map Method [4, 1931]. The resistivity map of the soil gives the value of the apparent resistivity of each point where a measurement has been made. It is similar to a geological map, but, in place of the lithological or palaeontological characteristics which normally serve to differentiate the terrains, it substitutes the value of a physical parameter, the resistivity.

In order to draw up a 'resistivity map' the 'apparent resistivity' of the underlying ground at a series of stations is measured by means of a constant quadripole $AMNB$, that is to say, with a constant 'depth of investigation'. This constitutes a horizontal exploration of a uniformly thick layer of ground. The measurements are plotted on a topographical map. Equiresistivity curves are traced by interpolation. It is often an advantage to establish 'profiles of resistivity' taken along a given line, which are interpreted as a cross-section of the terrains, and to draw up two resistivity maps with two different depths of investigation for the same region. [Greater depth of search is secured by increase of the lengths AB and MN.] The work at shallow depth concerns the superficial formations, that at greater depth the deeper subsoil. The map must cover the area to be studied without any gaps in order to give a general picture free from all preconceived ideas. It therefore constitutes a systematic and intensive study, frequently comprising many thousands of readings.

Electrical Soundings [2, 1932, 1934]. An electrical sounding consists in taking, at a central point on the surface of the ground, a series of resistivity measurements by means of a quadripole $AMNB$, whose length, and thereby whose investigation depths, are progressively increased. The apparent resistivities thus obtained are marked as ordinates on a diagram, the lengths of AB being marked as abscissae.

The interpretation of such a diagram consists in computing the values of the resistivity of the rock at the different depths beneath the measuring-station. Once the solution is known, it is easy to draw useful geological conclusions, such as the depth of a key horizon formed by the contact of two sedimentary formations with different resistivities. The tectonic map of a region, and particularly of a petroliferous structure, can therefore be established from a sufficient number of electrical soundings.

Obviously, such a problem has a real meaning only if the volume of soil beneath the quadripole, affecting the measurements, is formed of a succession of homogeneous and horizontal superimposed layers. These conditions are never exactly fulfilled, but experience has shown that with slightly sloping formations, electrical soundings still give sufficiently correct results if certain precautions are taken.

Even with homogeneous and horizontal formations it is possible to give a single and definite interpretation of an electrical sounding only if certain simplifying hypotheses are adopted. At least, so some mathematicians claim to have proved. On the contrary, the reciprocal problem has been solved exactly. It is possible to compute mathematically the electrical sounding diagram for a soil composed of a number of horizontal layers of known thickness and resistivity. The calculation, made by using Maxwell's Theory of Images, is only possible in practice if the number of layers is not too great, and if the deepest one is supposed infinitely thick.

For a practical survey the following course is adopted. Certain simple hypotheses are assumed concerning the resistivity and the thickness of the beds in the region under consideration. A series of graphs is then calculated, each corresponding to different thicknesses of the layers. Finally, the diagram actually obtained in the field is compared with these graphs. If an electrical sounding corresponds to one of the theoretical graphs, the geological interpretation can be made. If the coincidence is insufficient, the values of the resistivities adopted *a priori* are modified, and new graphs are calculated. This is, therefore, a process of successive approximations. The work is greatly facilitated by the preliminary electrical coring of a hole drilled in the region, giving the real resistivity of the successive layers, and their approximate thickness.

Examples of Application

Resistivity Map of Aricesti Dome (Roumania). This structure was studied in 1923 by the resistivity map method

at very shallow depth. Since 1932 deep drill-holes have encountered oil in the Meotic formations (about 5,500 ft. average depth) giving quite a good production.

Fig. 2 gives, in the form of equiresistivity curves, the map established in 1923 with a line *AB* of 1,300 ft. (400 metres). The investigation, therefore, included a layer of ground about 300 ft. deep.

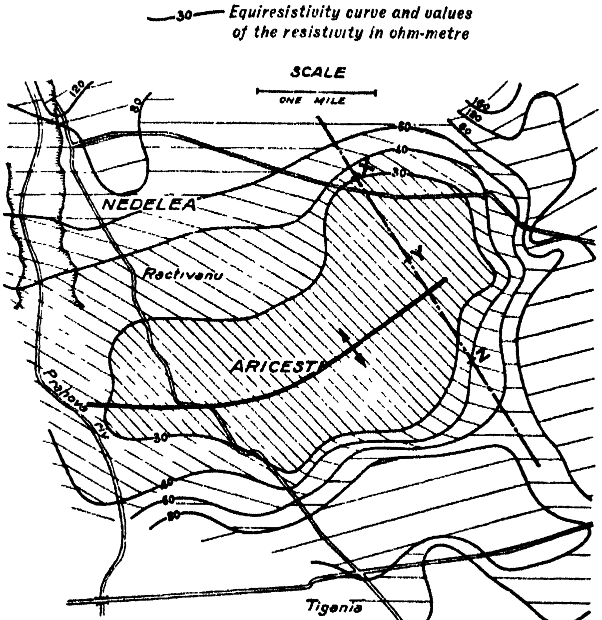

FIG. 2. Resistivity map of Aricesti Dome, Roumania, 1923. Length of line *AB* (see Fig. 1) is 1,300 ft.

The surface of the ground is very flat. It is formed of a Quaternary Terrace, with a resistivity of about 150, above Tertiary (Levantine) shales, having a resistivity of about 25 ohm-metres. As the Dome continued to rise during the Quaternary period, the terrace, constantly subjected to erosion, is thinner on the top of this structure than on the flanks (Fig. 3). It follows that the layer of ground studied electrically comprises at the top little resistive terrace and much conductive shale, giving an apparent resistivity of about 30 ohms; on the contrary, the terrace is thick on the flanks, and there are less shales, so that the apparent resistivity is higher, greater than 100 ohms in certain places. To sum up, the resistivity curves give quite a correct substructure map of the top of the Tertiary shales, but with an unknown depth scale.

Fig. 3 gives a cross-section of the Aricesti field along the line *XYZ*, as well as a resistivity profile also made along this line. This profile was established in 1933, that is to say, 10 years after the first electrical survey, and when the structure was known as a result of a number of drill-holes. The measurements were carried out with a line *AB* 7 miles long, corresponding to a very considerable investigation depth. The apparent resistivities found are rather low, this being due to the influence of the deep conductive formations. These reach about 10 ohm-metres on the top of the structure, which always appears on the diagrams as a point of minimum resistivity.

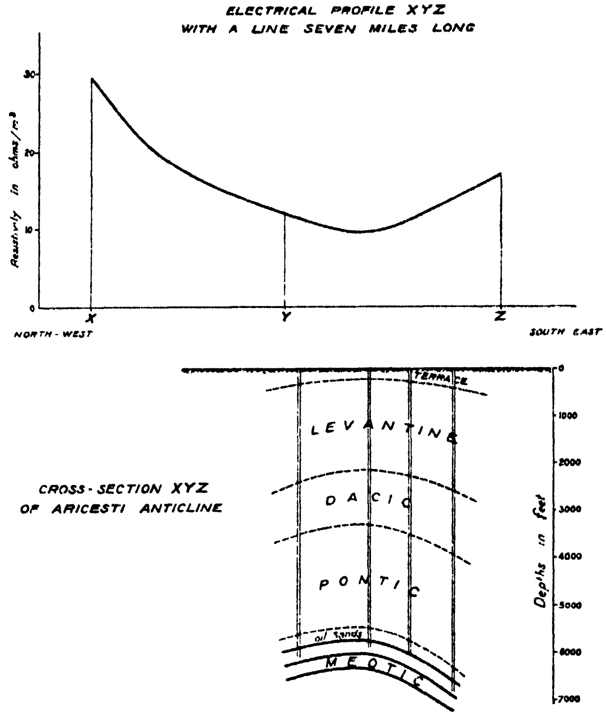

FIG. 3.

resistivities measured are, as usual, shown as ordinates, and the corresponding lengths of the line *AB* (see Fig. 1) as abscissae. It is seen that the resistivity decreases regularly as *AB* is lengthened, i.e. when the investigation depth increases. At the place of each electrical sounding I, II, III, a hole, drilled after the electrical survey, shows the exact depth of the Ducic/Pontic contact, which is taken as key horizon. At sounding I the depth is 5,550 ft., and the apparent resistivity 12·5 ohm-metres with a line *AB* = 10,000 ft. (3,000 metres); at sounding II the depth is 3,000 ft. and the resistivity 10·8 ohm-metres; at sounding III the depth is 1,800 ft. and the resistivity 8·3 ohm-metres.

Electrical Soundings in the Region of Bucsani (Roumania). Fig. 4 shows three electrical soundings executed in 1934 for the study of the tectonics of this region. The apparent

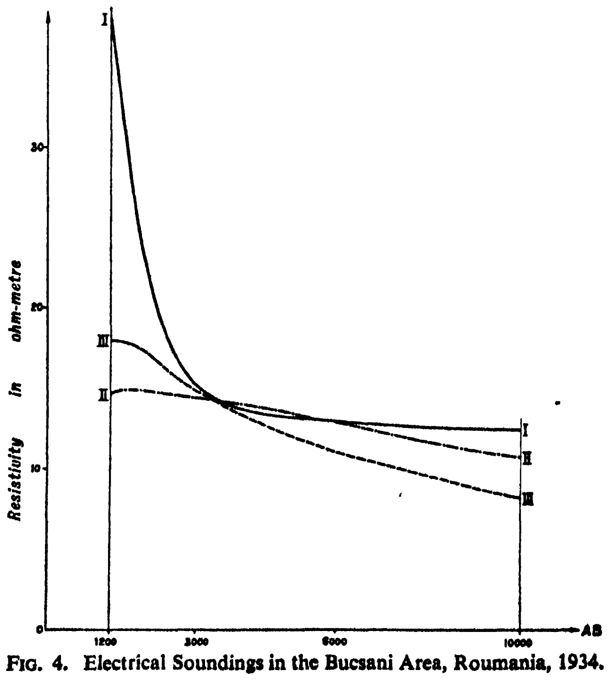

FIG. 4. Electrical Soundings in the Bucsani Area, Roumania, 1934.

The interest in this example is essentially a practical one. In spite of the very slight differences of resistivity that were measured, the interpretation of numerous electrical soundings made clear the structure of Bucsani, a region which has very recently proved itself to be a new oilfield with an excellent production.

Two remarks may be added about these electrical soundings.

The interpretation of the diagram was facilitated by the fact that electrical coring had previously given the mean resistivity of the different formations (Levantine, Dacic, Pontic, Meotic) of the region. Therefore the problem reduced itself to determining the thickness of these formations.

On a resistivity map made with a line $AB = 10{,}000$ ft., the Bucsani anticline shows up as more conductive than the surrounding formations, as does the Aricesti Dome. A map established with a line only 1,300 ft. (400 metres) long (like that used in 1923 at Aricesti) would have led to an erroneous interpretation. The station II would, in fact, have appeared to be at the top of the structure, whereas, in reality, station III is tectonically higher. This shows the utility of electrical soundings with a correct interpretation of the depth of key horizons.

ELECTROMAGNETIC METHODS

These measurements, which are based on the determination of the magnetic field produced by currents circulating in the ground, have for one particular object the study of the strata dips, a fundamental problem in prospecting for petroliferous formations. Two techniques which have been widely applied will be briefly described.

The Loop Method [2, 1932, 1934]. On the surface of the ground is placed a large loop S, composed of an insulated conductor, and comprising a device for the measurement of the electro-motive forces induced in S. This loop is an exact square, with each side 100 ft. or more. Along the two diagonals of this square, two straight wires AB and $A'B'$ are placed, from 300 to 2,000 ft. long, and grounded at both ends. If the soil under the loop S is formed of homogeneous, horizontal strata, an alternating current sent through AB induces no electromotive force in S, this by reason of symmetry. If the strata dip, the flow of the current between A and B has an average deflection corresponding to the dip, because of the anisotropy of the ground. The symmetry between the loop and the average flow no longer exists, and an electromotive force is induced in S. From the direction and value of this electromotive force the component of the dip of the strata perpendicular to AB can be estimated. In sending current through $A'B'$, the component of the dip perpendicular to this line may also be obtained. The resulting vector of the two components gives the real direction of the dip of the formations. The device is reversible. Alternating current may be sent into the loop S and the electromotive force of induction measured in the circuits AB and $A'B'$.

The process is only correctly applicable to fairly anisotropic media (interbedded shales) with more or less regular resistivities.

Fig. 5 gives the results obtained on the flanks of an anticline at Grozny (U.S.S.R.). The dip arrows coincide well with what is known of the structure.

Swedish Method [5, 1931]. This method gives the depth and the electrical properties of certain conductive key horizons, as well as their dip.

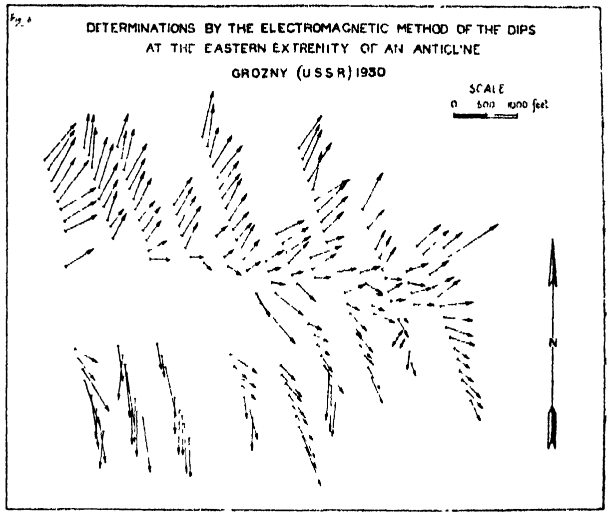

FIG. 5.

As can be seen from Fig. 6, which shows a perspective view of the device, there is placed on the surface of the ground a very long, straight, insulated wire, whose two ends A and B are grounded and through which is sent an alternating current of varying frequency. At a series of stations placed along a profile perpendicular to AB, the magnetic

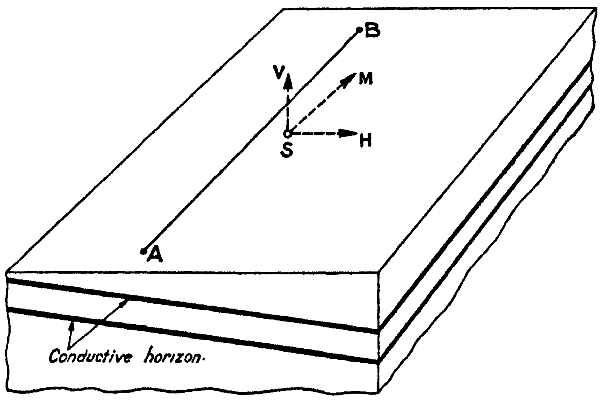

FIG. 6. Principle of Swedish Induction Method.

vector produced both by the primary current flowing through AB into the ground and by the secondary currents induced in the ground is studied. The line AB is 1 or 2 miles long; the distance of the stations from the line is several hundred feet; the frequency of the alternating current used varies from 10 to several hundred per second.

The magnetic vector M at the station S is the resultant of two components: the one V, vertical, and the other H, horizontal, the former being the more important. The two components V and H are measured in amplitude and phase, in relation to the primary current sent through the line. This determination is made by means of a search coil of a few hundred turns, provided with an amplifier and a compensator connected to the primary current.

The two components V and H may be calculated theoretically when the ground, from the point of view of its electrical conductance, is confined to one or two horizontal conductive planes, situated at known depths. These computations may be completed by laboratory experiments on reduced models. Graphs are then drawn which, for a

station *S*, give the depths of the conductive horizons as a function of the different magnetic factors.

In practice the geological interpretation of the measurements is made by supposing that the electrical conductivity of the ground is concentrated into three key horizons: one on the surface of the ground; another at shallow depth; the third at great depth, representing the formations to be studied. The depth of this last key horizon is, therefore, computed for different distances from the line *AB*. The repetition of these measurements at numerous stations allows the dip to be determined and the map of the structure to be traced.

Although this process may appear, *a priori*, to be based on rather theoretical simplifying hypotheses, it has been applied on a large scale and has rendered numerous services, particularly for the study of faults.

CONCLUSIONS

As has been shown in this short summary, electrical prospecting methods are complex and their many techniques lend themselves to very varied applications. Up to the present time, it is this branch of geophysics that has given rise to the most extensive theoretical and mathematical researches, and on reading some of the articles on the subject a wrongly pessimistic impression may be got that the intricate formulae conceal poor practical results. This is particularly striking when one compares it with the successful Seismic Reflection Shooting, whose theory still appears primitive, only the technical details and the construction of the apparatus having been studied thoroughly.

There is a great deal of room for improvement in electrical prospecting methods. One of the difficulties encountered in this direction, however, is the impossibility of conducting accurate experiments in already exploited oilfields, where the tectonics are well known. Casings and pipelines here form such a vast network of excellent metallic conductors that they completely upset electrical measurements, whilst they have no effect on seismic and gravimetrical experiments.

The latest improvements consist, above all, in the increase of the investigation depth, that is to say, in the use of longer measuring-devices. Lines 2 or 3 miles long, with an investigation depth of several thousand feet, are quite usual to-day, and lines of even 7 miles have been employed in certain favourable districts. Experienced operators obtain a relative precision of 1/20 in their measurements, despite the smallness of the difference of potential to be measured (a few millivolts).

Although the measurements remain correct, their geological interpretation becomes more and more delicate as the length of line is increased. These affect such immense volumes of soil that more than one structure may be included and the facies of the formations may vary. The computation of the electrical sounding becomes especially uncertain in cases where the sedimentary layers affecting the measurements can no more be considered as even roughly homogeneous and horizontal. Electrical studies at great depth can therefore only be applied to very gently sloping folds, such as those found in plains far from mountain ranges. As a matter of fact, these difficulties are encountered by all geophysicists, Seismic Reflection operators alone escaping this general misfortune.

The use of direct current or, at least, of very low-frequency alternating current (inaudible frequency) is imperative for exploration at great depth. In such a case, when a current is sent into the ground, the establishment of the potential equilibrium at the surface of the ground, according to Ohm's law, takes an appreciable time. As a result of skin-effect, i.e. the induction between different current lines, the electrical current first remains mostly at the surface of the ground, and only penetrates gradually. This action is more marked as the ground is more conductive, and, as petroliferous formations are nearly always very conductive, skin-effect is very noticeable in their case. With high-frequency alternating current, the flow changes its direction before attaining the permanent equilibrium, and the deeper layers barely affect the measurements at all.

Electrical prospecting for oil has been applied principally in the U.S.S.R. and Roumania, where important results have been obtained. In these two countries one finds vast shaly formations constituting very regular electrical key horizons. Also, the resistivities of the different superimposed layers decreases as the depth increases, and this condition is propitious for deep investigation. On the contrary, in the U.S.A. favourable electrical markers are often absent, whereas good seismographical ones are numerous; and this accounts for the very remarkable results of seismic surveys in that country. As can be seen, everything depends on local conditions, and it is difficult to say, *a priori*, without a careful study of the geology, what practical services electrical prospecting can render in a new oil region, where no electrical test has yet been made.

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ELECTRICAL CORING

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CONTENTS

I. INTRODUCTION

THE basis of the technique known as 'electrical coring' consists in determining the lithological nature of the formations encountered in a drill-hole by means of electrical measurements made inside this hole. In the case of oil exploitation, the only one which will be considered here, the essential problem is the determination of the characteristic geological horizons or markers and of the oil and water sands. The term 'electrical well surveying' is also used as well as 'electrical logging'. Literally, the words 'electrical coring' are not quite correct, but their meaning is obvious and they have already become a part of oil-field terminology. They lay stress upon the fact that the object of the technique is to substitute electrical measurements for mechanical coring.

Electrical coring, which was first studied in the small French field of Pechelbronn, was applied in Venezuela in 1929, and then in the U.S.S.R., where it rapidly became very widely used. It was introduced into Roumania in 1931, and then successively into almost all the oil-producing countries in the world. Up to the present, however, this method has been very little used in limestone fields, so that its possibilities in these formations are still imperfectly known.

The principal publications dealing with this subject are papers presented at different congresses; these are indicated in the Bibliography at the end of this article. To these papers could be added a long list of patents and numerous articles which have been published, chiefly in the U.S.S.R.

Even if electrical coring reminds one of surface electrical prospecting, there are essential differences between the two techniques. In surface prospecting for oil, one deals with roughly horizontal beds, that is to say, beds more or less parallel to the line along which the instruments are moved, and the ground must be explored to a great depth. For this purpose the electrodes must be placed great distances apart. Each measurement must, therefore, affect large volumes of soil. On the other hand, inside the drill-hole the device is moved more or less perpendicularly to the different beds. The electrodes are close to the formations to be explored, and a measurement of a local character only is required. The electrodes are, therefore, placed very near to each other, the volume of soil affected by the measurement consisting of only a few cubic metres at the most.

Geophysical problems inside drill-holes are comparatively easy to solve, due to the fact that the instruments are in close contact with the part of the soil to be studied. It might even be said that the measurement of the electrical properties is here carried out under conditions which, technically, are the most ideal, because of the regularity of the hole, which very often has a nearly perfect cylindrical form, and of the complete homogeneity of the mud. Owing to the possibility of moving the electrodes in the hole inch by inch, the precision is such that it almost gives a feeling of working on a laboratory table. At the same time, instead of connecting wires of a few metres length, such as are used in a laboratory, the electrodes and the measuring instrument are connected by a cable several kilometres long. The measurements must be taken very rapidly throughout a great depth, so as not to inconvenience the drillers, and in case caving-in occurs in the hole that is 'standing' without mud-circulation; and, finally, the operator is not working in a closed laboratory, but often in mud and rain, and he is still obliged to make accurate measurements with delicate apparatus, the presence of which amidst heavy drilling machinery seems rather paradoxical. This means that, although the theory of electrical coring is fairly simple, the practical execution is less so.

The two parameters in use at the present time in electrical coring are the specific resistivity of the formations in the immediate vicinity of the hole, and the spontaneous potentials (in brief, S.P.) which develop in the drilling-mud at the level of certain beds. These potentials are related to the permeability of the beds (as we shall see farther on), and it is often stated, rather incorrectly, that it is the 'permeability' (or even less correctly, the 'porosity') that is measured.

It is obvious that other electrical parameters can be utilized. In particular, it is possible to measure with a fair degree of accuracy a coefficient of the electrolytic capacity of the beds, and this differentiates clearly between sands and clays. Other physical properties, such as thermal conductivity, are also capable of giving rise, in the future, to new possibilities in the diagnosis of formations. However, as these different techniques have not yet been widely applied, the only measurements that will be described completely hereunder will be those of resistivity and 'permeability'.

II. PRINCIPLES AND TECHNIQUE OF ELECTRICAL CORING

(*a*) **Electrical Resistivity of Rocks.** The electrical resistivity of a rock (the word rock implies here any kind of

formation) is the resistance of a cylinder having unit length for height and unit surface for section. It is usual to take the metre as unit, and to consider resistivity in ohms per cubic metre (ohm-metre).

Different formations have widely differing resistivities—from a few tenths of an ohm up to several thousand ohms per cubic metre.

With the exception of certain metallic ores, rocks possess a conductivity which is exclusively electrolytic; in other words, the solid elements composing the rocks are virtual insulators, and only the interstitial absorbed water enables the current to flow through them.

The specific resistivity of rocks can be deduced approximately from the following law: The specific resistivity of a rock is inversely proportional to the amount of water contained in each cubic metre of the rock and to the conductivity of this absorbed water. It can be stated therefore that it is roughly inversely proportional to the amount of dissolved salts in each cubic metre of rock.

Such secondary factors as the geometrical distribution of the absorbed water in the interstices of the solid elements of the rock, the capillary action of these elements on the free ions, the chemical nature of the dissolved salts (sodium chloride, for the greater part, in oil-field formations), and finally the anisotropy existing in most sedimentary rocks have been omitted.

On the other hand, one factor which does play an important part is temperature. A rise of temperature causes a decrease of resistivity, which may be reduced to half its value by an increase in temperature of 50° C., and it is certain that variations of 50° C. are often met with in drill-holes.

It has been said that the resistivity of a rock depends essentially on the nature of the absorbed fluid. An extremely important factor in the electrical exploration of drill-holes results from this. Impermeable formations such as clay possess a constant resistivity, since extraneous liquids cannot filter into them; on the contrary, permeable formations (sands) have varying resistivities, according to the nature of the liquid they contain. These formations will be very conductive if the liquid is salt water; conversely, they will be resistant if the liquid is oil.

(*b*) **Resistivity Measurements in Drill-holes.** It must be recognized that resistivity and permeability measurements can only be made in the uncased part of the drill-hole. A metal casing forms such a perfect electrical conductor, in comparison with the surrounding rocks, that it acts as an impenetrable screen preventing any electrical investigation by means of apparatus placed inside the drill-hole. On the other hand, the resistivity can only be measured easily if the hole is filled with mud or water, thereby ensuring the electrical connexion between the electrodes and the soil. In an empty hole it would be necessary to establish reliable points of contact with the walls of the hole, a problem not easy to solve. Finally, the presence of water is indispensable for the creation of spontaneous potential phenomena which are related to permeability. From the above, it can be seen that electrical coring can be applied most advantageously to rotary wells, as these generally have a large amount of uncased hole, and are always full of water—or rather mud. On the contrary, cable-tool wells cannot be studied so easily, because there is usually only a small length of open hole between the casing-shoe and the bottom.

The resistivity of the rocks penetrated by drill-holes can be measured in different ways. Devices with one, two, three, or four electrodes that are lowered into a drill-hole have been suggested. Details will be given of the three-electrode method which, up to the present, is the most commonly applied in practice. A few words will be written about the one-electrode method, which has been experimented with for a special purpose.

Fig. 1 shows the principle of the three-electrode device.

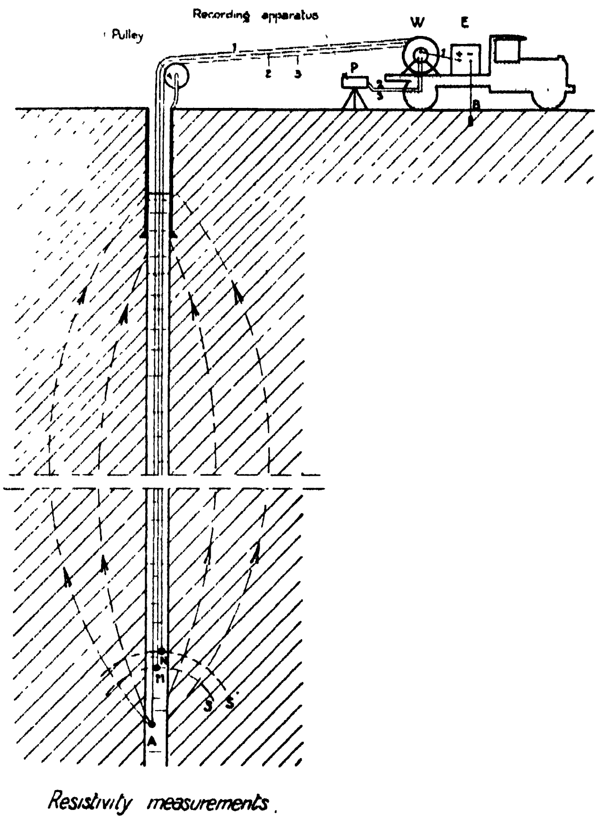


FIG. 1. Scheme of electrical coring device.

A cable composed of three conductors, 1, 2, and 3, wound on a winch W at the surface, is lowered into the drill-hole. To the ends of these three conductors are attached three electrodes A, M, and N, which thus hang in the drilling-mud, and can be raised and lowered by means of the winch. The distances $AM = r$ and $AN = r'$ are constant and are chosen so as to be relatively important as compared with the diameter of the hole. By means of conductor 1, electrode A is connected to a source of direct or alternating voltage E, whose other pole is connected to a ground-electrode B, placed in the neighbourhood of the drill-hole. The upper part of the casing already in the hole is generally taken as ground electrode. The current sent out from electrode A spreads into the ground all around A and, by ohmic effect, creates between M and N a difference of potential, which is measured at the surface by a potentiometer P, adapted to the kind of current produced by E (direct or alternating, as the case may be).

The distance r and r', the intensity i of the current, and the difference of potential ΔV between M and N being known, the specific resistivity ρ of the formations in the vicinity of the measuring-device may be computed if the surrounding formations are homogeneous. The formula is established in the following manner. In flowing away from

electrode A, the current i gives rise to a series of equipotential surfaces around A. In the region of the electrodes M and N (that is to say, neither too near nor too far from A) these surfaces are, for reasons of symmetry, spheres centred on A. The presence of the column of mud or water in the drill-hole brings about no important distortion of these surfaces, particularly if the resistivity of the water does not differ too much from that of the formations. In these conditions, the reading of the potential drop between M and N corresponds to a measurement made inside the formations between the same distances r and r' from electrode A. The application of Ohm's law to the spheres S and S', passing through M and N, leads to the formula:

$$\rho = 4\pi \frac{\Delta V}{i} \frac{rr'}{r'-r}.$$

Up to the present it has been supposed that the formations in the neighbourhood of the device were homogeneous, and that the disturbing effect due to the presence of water or mud was negligible. But these hypotheses are never quite exact. Therefore the formula does not give the real resistivity, but a species of mean resistivity affected by all the elements present in the region under consideration (mud, water, different rocks). This mean resistivity is distinguished from the real resistivity by the name of 'apparent resistivity'. According to circumstances, it can be either smaller or greater than the real resistivity of the most resistant or of the most conductive elements present.

The problem of calculating the real resistivities from the apparent resistivities which have been measured is treated by means of the general mathematical theory of Newtonian potentials. Particular account must be taken of the diameter of the hole, the resistivity of the mud or water filling the hole, the thickness of the bed whose real resistivity is desired, the position and the dimensions of the measuring-device. The results which are obtained in this way are often very startling, and sometimes even seem paradoxical. In practice, fortunately, it is often possible to give a geologically correct interpretation of the readings based entirely on the apparent resistivity. Naturally, the size of the measuring-device must be suited to the particular problem to be studied; likewise the person who interprets the readings must be conversant with the possible peculiarities of the apparent resistivity. It may be concluded from these remarks that resistivity measurements, which at first sight appear very simple, are, in reality, rather complicated when a great degree of accuracy is desired.

The method of resistivity measurement by means of a single electrode lowered into the drill-hole is based on the following principle: The electrode A is attached to the lower end of an insulated cable C, whose upper end is connected to a ground electrode B (usually the casing of the hole). The resistance R of the circuit, comprising the cable C, its two ends A and B, and the formations between A and B, is measured by means of a suitable apparatus. This resistance R is the sum of three terms:

(1) The resistance R_1 of the cable C, which must be measured beforehand.

(2) The resistance R_2 of the ground-electrode B (the ground *around* B) which is negligible if this electrode is of large size (for instance, the casing), and which can in any case be measured exactly by well-known methods.

(3) The resistance R_3 of the ground-electrode A (the formations *around* A).

The known resistance R of the circuit is therefore:

$$R_1+R_2+R_3.$$

The part of the formations between A and B, but distant from these two electrodes, has practically no effect. In fact, its ohmic resistance is absolutely negligible, because of the very wide section offered to the current.

To summarize, we have the formula:

$$R_3 = R-(R_1+R_2).$$

Now R_3 is of the form $K\rho$, where ρ is the resistivity of the formations in the neighbourhood of A, and K is a geometrical coefficient depending on the shape of the electrode A, which can be either measured or calculated beforehand. The resistivity ρ can, therefore, be deduced from the value of R_3 and hence from the measurement of R.

This method, which is much less accurate than that employing three electrodes, was first described in the Schlumberger U.S. Patent No. 1,819,923, and then experimented with under the following form (Karcher Patent No. 1,927,664): The bit is taken as electrode A, and is electrically insulated from the drill-pipe. Cable C is fixed along the drill-pipe. The resistance R of the circuit is measured by reading the intensity of the current produced by a source of known electromotive force. The system can obviously only give rough results. It could be applied during normal drilling operations if all technical problems involved were practically solved. The greatest difficulty is the insulation of the bit, and the whole process is still in an experimental stage.

(*c*) **Spontaneous Potentials in Drill-holes.** A curious phenomenon was discovered during geophysical studies in drill-holes: that of natural currents existing spontaneously in the drilling water or mud at the level of permeable beds. By ohmic effect in the liquid, these currents give rise to differences of potential which are very easy to measure. The current may reach the value of several milliamperes, corresponding to differences of potential of 1 to 200 millivolts. The part played by this phenomenon in the electrical exploration for oil is easily understood. In fact, the determination of permeable beds is absolutely essential for the recognition of oil and water sands and for the correct placing of water-shut-offs.

Two different phenomena for explaining these spontaneous potentials are considered, and have been investigated thoroughly in the laboratory. They are electro-filtration and electro-osmosis.

(1) *Electro-filtration.* When, by exterior pressure, an electrolyte is made to filter through a dielectric, for instance water filtering through sand contained in a glass tube, an electromotive force E is observed between the two ends of the tube, and is given by the formula

$$E = K\rho(P-p),$$

wherein K represents a coefficient depending on the nature of the dielectric and the viscosity of the filtering liquid, ρ the resistivity of the latter, P the pressure at the entrance, and p the pressure at the end of the tube. This phenomenon, which has been known for a long time, is due to the friction of the liquid against the grains of the dielectric.

In drill-holes (Fig. 2), and at a given level, the mud filling the hole exerts a pressure P, which is generally higher than the rock-pressure p at the same level. Under these conditions,

the water of the mud penetrates into the permeable bed, and this percolation produces an electromotive force. The water of the drilling-mud acts as the electrolyte and the permeable bed as the dielectric. In particular, the electromotive force is proportional to the resistivity of the water of the mud and to the difference between the pressures P and p. The electric current flows in the same direction as the filtration, that is to say, in general, the lines of current enter the layer. Thus, at the level of a permeable layer, everything takes place as if the wall of the drill-hole were becoming charged with negative electricity. As a result, a vertical section of the potentials, taken throughout a drill-hole, will show up a negative irregularity at the level of a permeable layer.

As a matter of fact, the irregularity can sometimes be of the opposite sign. The existence of a positive centre indicates the presence of a layer whose liquid tends to flow into the drill-hole, that is to say, a high-pressure formation.

(2) *Electro-osmosis*. It is known that, when two electrolytes are in contact, an electromotive force is observed, having the value:

$$E' = K' \log \frac{\rho'}{\rho}.$$

ρ' and ρ are the resistivities of each of the electrolytes, K' is a constant depending on the chemical composition of the fluids and on the nature of the contact existing between them.

In a drill-hole the electrolytes are generally the drilling-mud, and the salt water existing in the permeable layers. This water obviously exists in water sands, but it also exists, in capillary form, in most oil sands.

In the usual case, where the water of the permeable layer is more salty than that of the mud, the lines of current have a tendency to penetrate into the layer and, under such conditions, the potential profile shows a negative irregularity. Consequently, the separate effects of electro-filtration and electro-osmosis are additive. The reverse is of course also possible.

Generally, electro-filtration is stronger than electro-osmosis, but it has not yet been possible to determine exactly the part played by each in the production of the spontaneous potentials measured in a drill-hole. When the pressure P of the mud is increased, for instance, by means of a pump, after closing-in the casing-head, the electromotive force of filtration E is increased. If the salt content of the mud is changed, the electromotive force E', of osmotic origin, is modified. The resulting variations of spontaneous potentials produced by a permeable layer should make it possible to compute either the pressure p existing in this layer, or the salinity of the water absorbed by it. In any case, it may be said that these determinations present certain difficulties and have as yet no widespread application in practice.

From these considerations it follows that, although the measurement of spontaneous potentials proves *qualitatively* that the wall of a drill-hole is permeable, it does not in any way constitute a *quantitative* measurement of this permeability, that is to say of the rate of flow of a fluid of known viscosity under the action of a known difference of pressure. A detailed discussion has shown the complexity of the problem, but, as in the case of apparent resistivity, it is not necessary to go right to the root of these questions before being able to draw very interesting practical conclusions from the spontaneous polarization, and thus give a correct geological interpretation.

(*d*) **Permeability Measurements.**—The measurement of spontaneous potentials is a simple operation; its technique is seen on Fig. 2.

An electrode M is lowered into the drill-hole by means of an insulated electric cable, and a second electrode N is placed at the surface. The two electrodes are connected to a potentiometer P which, for each position of the electrode M, gives the difference of potential between M and N. As N is always kept at a fixed point and its potential is thus invariable, all that is necessary in order to obtain a relative profile of potentials throughout the drill-hole is to mark on a diagram the different readings taken between M and N.

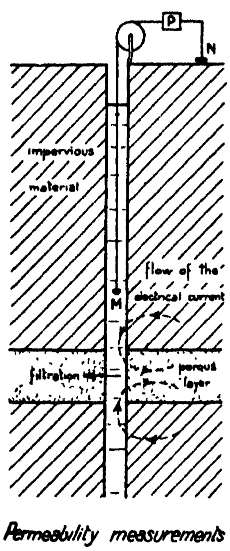


FIG. 2. Scheme of electrical coring device.

When great accuracy is desired, it is preferable to use non-polarizable electrodes. Generally, the best way is to take lead electrodes, within a porous container, holding a soluble lead salt (acetate or nitrate). Sometimes ordinary lead electrodes are sufficient.

Practice has shown what precautionary measures are necessary, and when these are taken, readings are exact to one millivolt, even at the greatest depths (10,000 ft.). This accuracy is not unnecessary, as it is recognized that differences of potential of only a few millivolts may give interesting geological information.

Obviously, the presence of stray industrial currents may sometimes cause inconvenience. In general, natural telluric currents have only a small vertical component and do not give rise to any serious trouble. By employing two submerged electrodes placed close together, the effect of these disturbances is almost entirely eliminated, and even in the case of strong stray currents the local potentials caused by a permeable layer can be measured exactly.

(*e*) **Electrical Logs and Principles of their Interpretation.** Resistivity and permeability measurements are summarized in practice by two diagrams placed side by side, shown schematically in Fig. 3, which also gives the geological interpretation.

The logs are obtained by moving the measuring-device continuously throughout the drill-hole and recording the measurements by means of automatic apparatuses. The two logs are taken simultaneously during a single run, which saves time and ensures an exact correspondence between the two logs as to depth. Both the apparent resistivity, measured in ohms per cubic metre, and the spontaneous potentials, expressed in millivolts, are plotted as abscissae; the depths, which must be correct to a thousandth, or even a half-thousandth, are plotted as ordinates. For this, it is absolutely essential to use an electric cable that is exactly marked, and to take the measurements whilst raising the electrodes, that is to say whilst winding the cable on the winch. It is only by these means that the movements of the electrodes in the hole and the regular stretching of the cable, which is always subject to a certain elastic stretch, can be determined.

The geological interpretation of geophysical measurements is a complicated question. A single parameter, such as resistivity, is insufficient, since several completely different

Fig. 4. Photograph of heavy winch mounted on truck

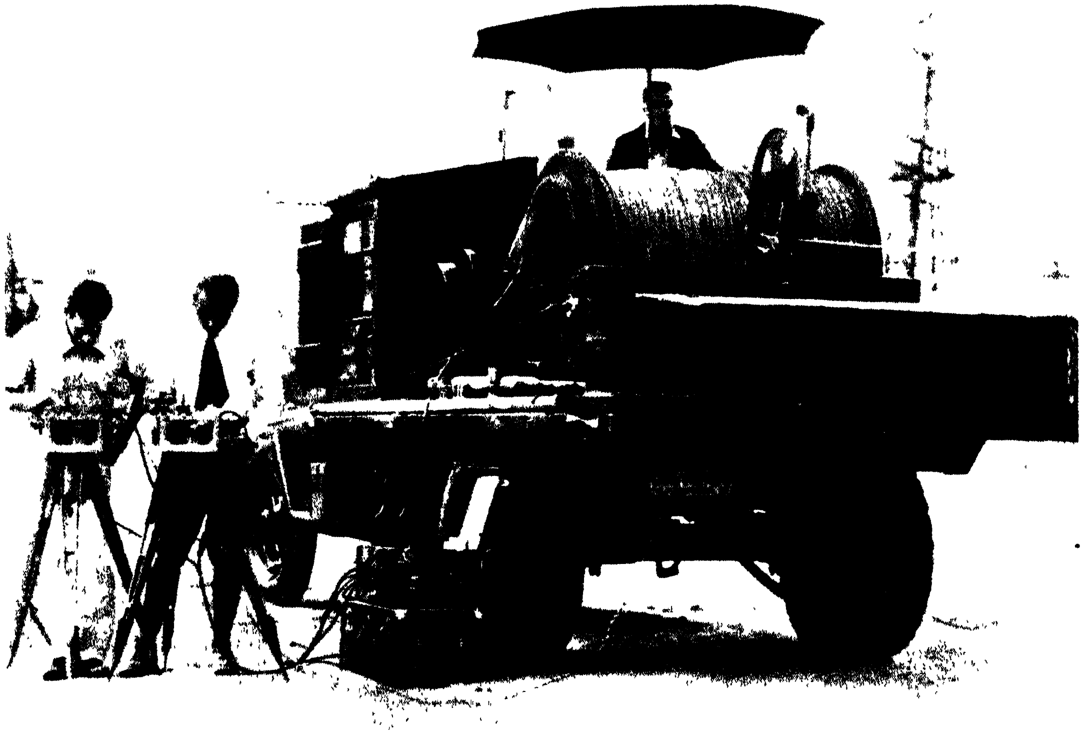


Fig. 5. Photograph of complete outfit in operation

rocks, such as sandstone, limestone, or an oil-bed, can have exactly the same resistivity. By adding a second parameter, such as permeability, the reliability of the diagnosis is greatly increased, and obviously the addition of a third parameter would be useful, assuming, of course, that it is quite independent of the first two. In practice, the task of interpretation is greatly assisted by a knowledge of the

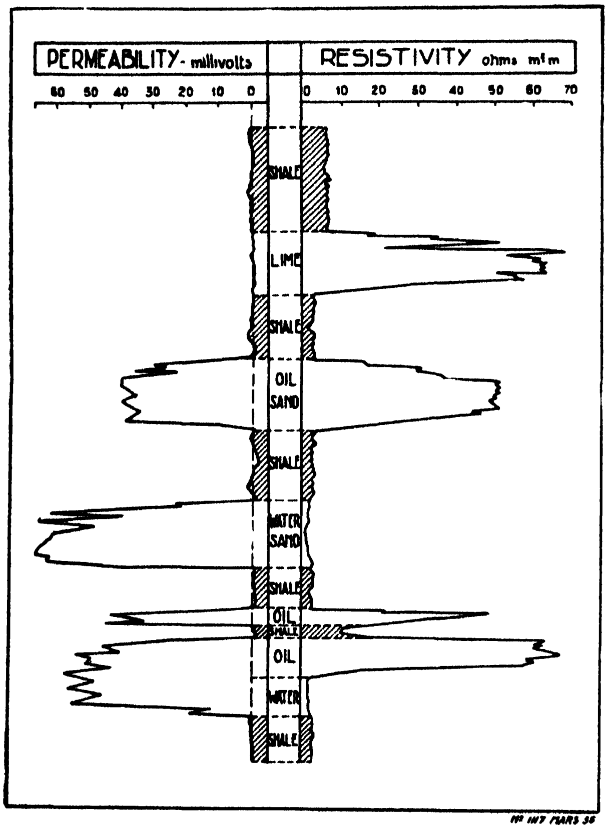


FIG. 3. Interpretation of Electrical Logs.

geology of the region under consideration. In holes in a well-known field, mistakes are usually insignificant. On the other hand, a geophysicist must not be blamed too much for mistaking a bed of coal for one of gypsum or limestone in an isolated wild-cat. A little common sense, and an estimation of the hardness of the bed from mechanical factors (such as the drilling progress in the bed), often enable the uncertainty to be cleared up.

Reading downwards, the following formations are apparent in Fig. 3:

(1) A shale, characterized by its low resistivity and its impermeability.
(2) A resistant (50 ohm metre) and impermeable limestone bed. A compact layer such as coal or gypsum would show up similarly.
(3) An oil sand, both permeable and resistant.
(4) A salt-water sand, permeable and conductive. A very sweet water sand could sometimes, but rarely, be mistaken for an oil sand (because of its possible high resistivity).
(5) At the bottom, a sand whose upper part is oil-bearing and whose lower part is water-bearing—quite a usual occurrence.

III. EQUIPMENT

The same instruments are used for resistivity and permeability measurements.

The three insulated conductors are twined together so as to form a single cable. This cable must possess both high mechanical strength (2, 4, or 8 tons, as the case may be) and excellent electrical insulation (several megohms per kilometre). This last quality is particularly difficult to secure, as the cable is immersed in muds which are often saline, hot, and at high pressure. The cable is kept taut by the weight of a plummet fixed at its lower end. This weight can vary from 25 up to 300 kg., and even more, when the viscosity and weight of the mud make it difficult to lower the device to the bottom of the hole. It is often necessary for the drillers to condition the hole carefully before starting an 'electric run' (either by using a reamer, or by circulating the mud for one or two hours after stopping drilling).

The upper part of the cable is wound on a winch, and its three conductors are connected to the three rings of a collector, which, in turn, are connected to the recording apparatus and to the source of current. For shallow wells, light winches (3,000 to 4,000 ft.) are available, worked by electricity and even by hand. In regions difficult of access, a winch, mounted on skids and driven by an oil engine, is used. In most cases, where it is possible to reach the wells by lorry, a strong and heavy winch is employed, capable of carrying more than 10,000 ft. of cable and of standing a strain of several tons. With this outfit the deepest wells can be surveyed (Fig. 4).

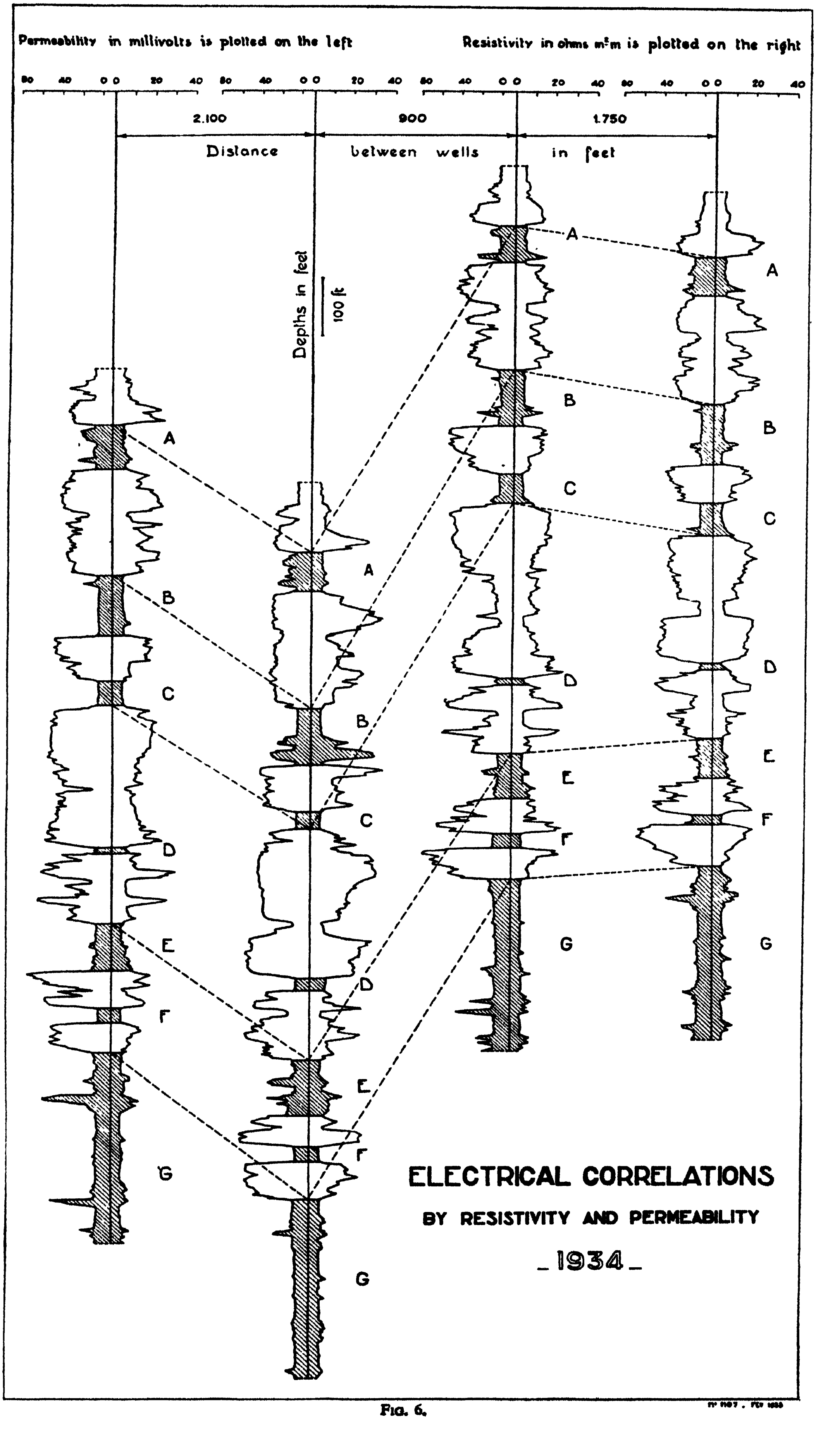
In the immediate vicinity of the winch, the cable passes through a measuring-device which shows continuously the length that has been unwound and which also actuates the unrolling of the paper on the recording-instrument. At the well-head the cable runs over a pulley to which is fixed a dynamometer indicating the tension.

The source of current is generally a dry-cell battery which produces either direct or alternating current by means of a commutator.

Potentials, whether direct or alternating, are measured preferably by a zero method with a specially adapted potentiometer. The recording is made on a paper unwinding at a speed proportional to that of the cable. In the semi-automatic apparatus in use at the present time, the operator constantly keeps the needle of the potentiometer at zero, by means of a handle controlling the tracing-pencil (Fig. 5). Entirely automatic apparatus will soon be available, and will eliminate all the tiring work for the operator, as well as possible errors. The tracing of the log can be made in a closed box, if it is wished to keep the results secret from the operators.

The simultaneous recording of the resistivity and permeability logs is made possible by the use of alternating current for the resistivity measurements. One of the potentiometers, only sensitive to alternating differences of potential, records the resistivity, whilst the other potentiometer, sensitive only to direct current, records the spontaneous potentials.

The speed of electrical coring depends largely on the requisite detail, and consequently on the depth scale that is adopted. This can vary from 1/50 for very accurate studies up to 1/1,000 for general investigation. With the semi-automatic apparatus the usual speed is about 1,000 ft. an hour, and it could be increased noticeably with a completely automatic apparatus. Including the setting-up and



Permeability in millivolts is plotted on the left
Resistivity in ohms m²m is plotted on the right
80 40 0 0 20 40 80 40 0 0 20 40 80 40 0 0 20 40 80 40 0 0 20 40
2.100
900
1.750
Distance between wells in feet
Depths in feet
100 ft
A
B
C
D
E
F
G
ELECTRICAL CORRELATIONS
BY RESISTIVITY AND PERMEABILITY
_1934_

FIG. 6.

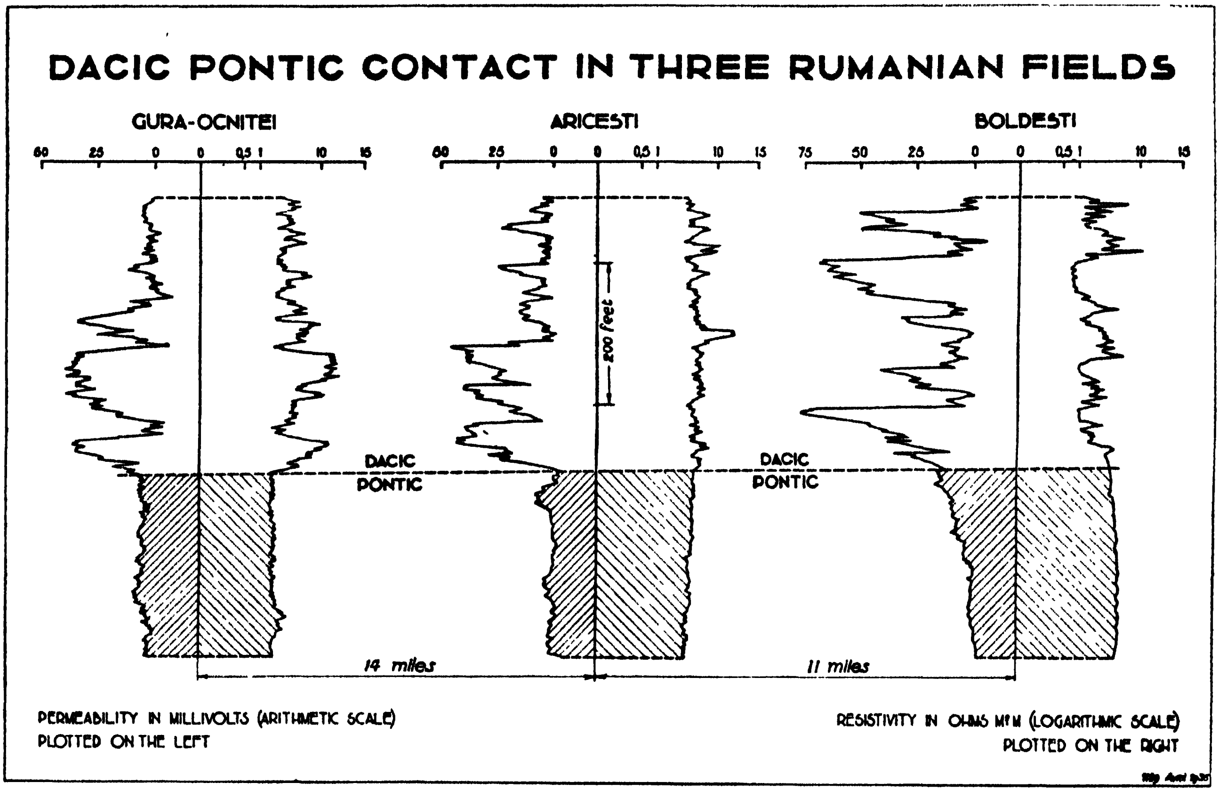


FIG. 7.

the removal of the equipment, the total time for a run varies between two and six hours according to the depth, the amount of open hole, and the difficulties encountered whilst lowering.

IV. APPLICATION OF ELECTRICAL LOGS

(*a*) **Geological Correlations.** The first problem that electrical coring has to determine is that of correlation between neighbouring wells. It is obvious that any physical parameter of the formations can be used for this purpose, if only this parameter shows up a constant value for a given formation over a large enough area, and if the values for different formations are sufficiently distinguishable.

In present-day practice, correlations are made on the basis of two parameters, resistivity and permeability, each possessing its own particular advantages according to the special circumstances. The best key horizons or markers in an oil region are generally the clays, or shales, which, because of their sedimentation far from a shore-line, show maximum regularity of facies and of thickness over large areas. Both their resistivity and permeability are low and characteristic. Sands, which are formed near shore-lines, are much more sporadic, and apart from this, their electrical parameters vary with the nature of the fluid they contain (oil, gas, salt water, fresh water).

Palaeontological key horizons are obviously unobserved by electrical coring unless they correspond to some lithological change as well. On the other hand, there sometimes exist excellent electrical markers, resulting from a slight variation in the average composition of the rocks, which are difficult to recognize by simple examination of mechanical cores.

Correlation is very easy when simple and clear electrical markers are present. It is much more difficult in oil series consisting of numerous beds of shale and sand, especially

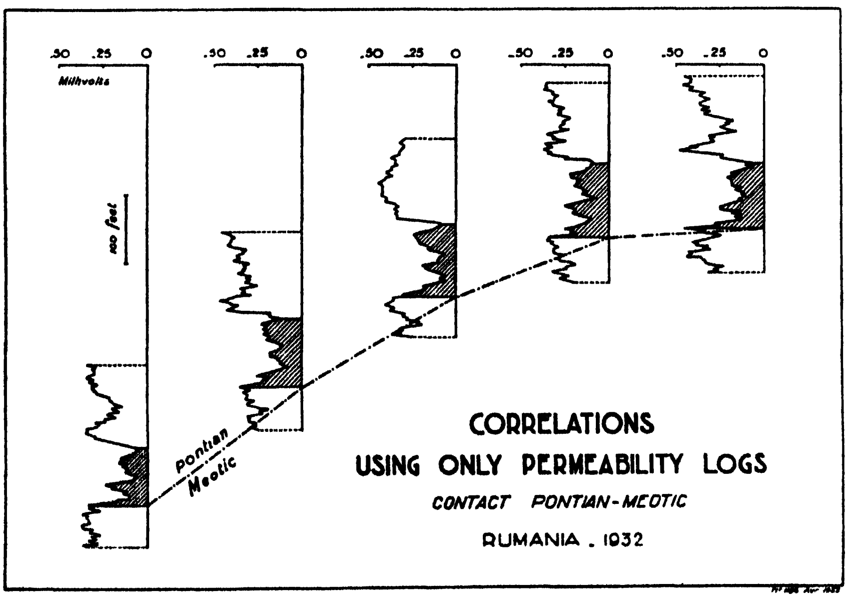


FIG. 8.

if the structures are steep and cut by many faults. It is precisely in such difficult cases that electrical coring renders the greatest service and gives a true notion of tectonics.

Electrical correlation between two wells is based essentially on the comparison of the form of their logs and on an endeavour to make them correspond as well as possible. The use of letters to indicate the different electrical markers is advisable. It has the advantage of avoiding risky geological assumptions. A few examples will make this clear.

Fig. 6 is taken from recent work in a tectonically complicated field in the Far East and is self-explanatory. There exists an alternation of sands (very permeable and very resistant) and shales (low permeability and low resistivity).

Fig. 7 is an example of the contact between the Dacic and Pontic series in three Roumanian fields. The Dacic is a zone comprising numerous sand-beds and giving rise to very irregular logs (it is to be noted that the resistivity is indicated on a logarithmic scale). Conversely, the Pontic is a very homogeneous marly formation (with low resistivity and slight permeability). Its appearance remains identical over a vast area, since the distance under consideration is about 25 miles.

Fig. 8 is an example of correlation by means of the permeability log only. It concerns the Pontic/Meotic contact in different wells of Gura-Ocnitzei and Gorgoteni (Roumania). This contact does not show up clearly on the resistivity log. On the contrary, very impermeable clays at the base of the Pontic give a very characteristic outline to the permeability logs.

Fig. 9 shows a section of the Grozny anticline—New Fields (U.S.S.R.), established according to the resistivity log.

(*b*) **Tectonic Studies.** Correlation work finally leads to the establishment of structural maps, which are drawn on one or several horizon beds or markers. These markers are located in each well according to the electrical log, as well as by mechanical coring. Likewise, as drilling proceeds, a 'normal' or composite well-log is made on the basis of the results of a careful study of the cores and the electrical logs of each well. Such a standard well-log shows the layers in their normal sequence, without any omission or repetition, and is taken as the basis of comparison for new wells. Electrical work, thus applied, very often leads to the discovery of faults and can explain anomalies encountered during exploitation. Formerly, such anomalies were often erroneously attributed to the lenticularity of the beds.

Fig. 10 gives a clear and simple example of a fault in a Venezuelan field. Well (1) is a typical hole, with two markers *A* and *B*, 450 ft. distant, as is usual. In well (2) the distance between these markers is only 110 ft. owing to the presence of a fault which cut out 340 ft.

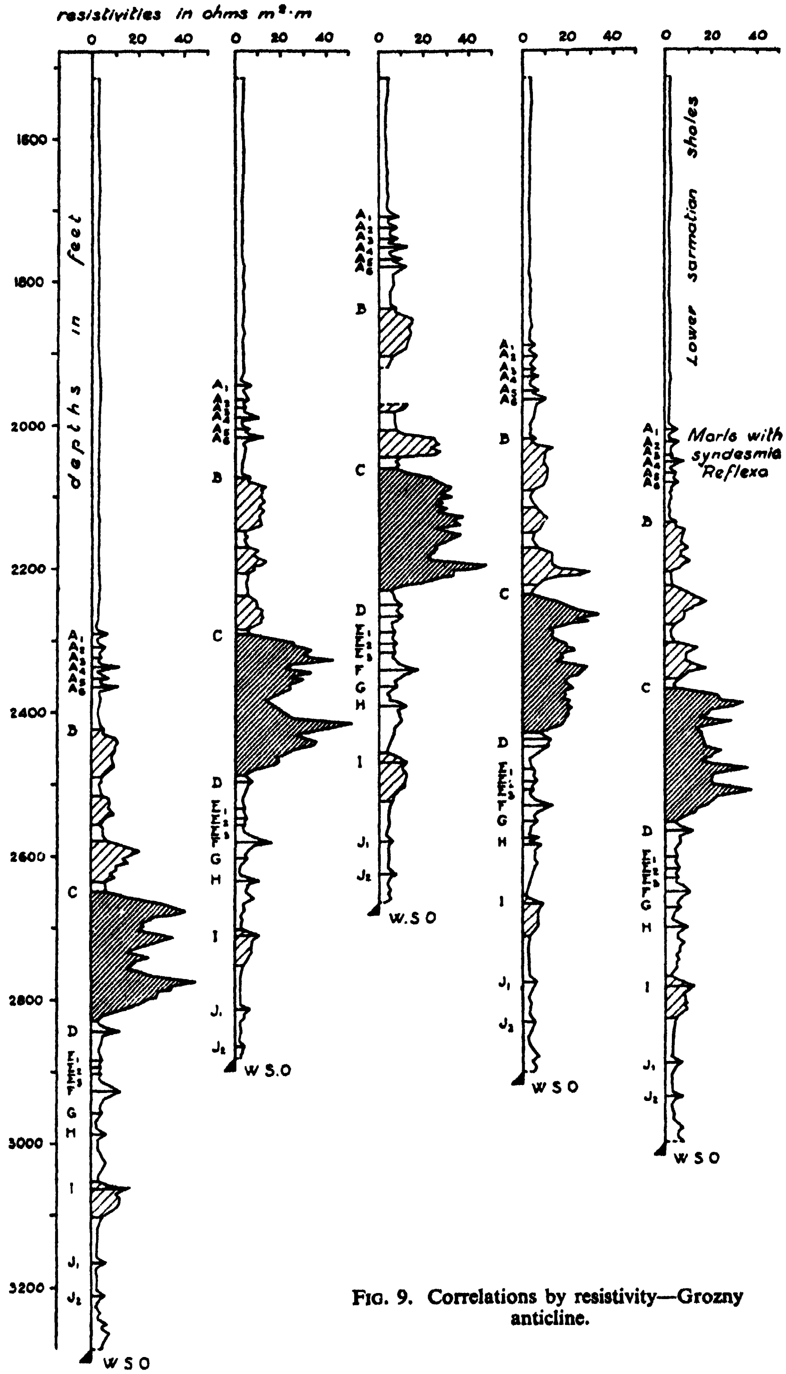


FIG. 9. Correlations by resistivity—Grozny anticline.

(*c*) **Detailed Study of an Oil Zone.** The study of an oil zone consists in determining exactly the positions of the oil, gas, and water sands, in order to set the water-shut-off at the right depth, to decide which sections are to be put on production, and finally whether any plugging back is necessary. Except in the case of work executed near already well-known wells, it is no longer merely a simple correlation that is needed, but a direct and absolute interpretation of the electrical measurements.

This is a difficult problem, and it must be admitted that in numerous cases an absolutely correct interpretation cannot yet be given. To begin with, the distinction between oil and gas is often rather doubtful. Then, some drilling-mud and particularly some of the water of the mud will always filter into an oil sand, and often conceal the usual high resistivity

of the oil, since the electrical measurement is only affected by the region close to the drill-hole, that is just where filtration is most important. This drawback is most serious with light oils. Beds of thick, oxidized, and viscous oil, on the contrary, show up very clearly on the logs, sometimes even in too marked a manner.

In spite of some technical imperfections this method

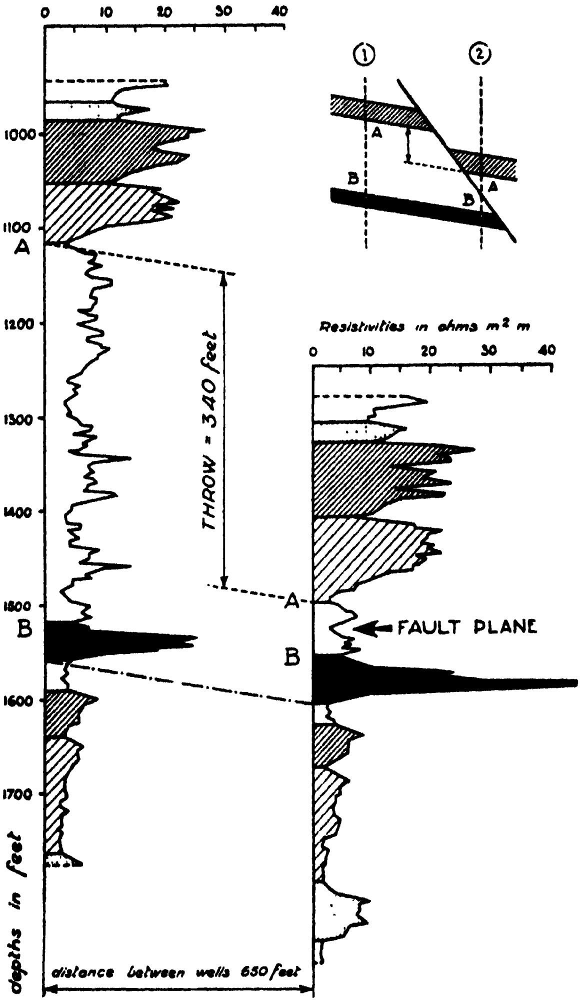


FIG. 10. Determination of a fault—Venezuela.

has already proved itself to be a very great help to this important branch of oil exploitation. In favourable cases, which are numerous, the interpretation is absolutely reliable. The position of the clays or shales, where the water-shut-off should be made, is always well defined electrically, since a mistake in the diagnosis of clays is almost impossible.

The example of Fig. 11 comes from Trinidad, and is quite recent. The electrical interpretation, which was verified when the well came into production, is shown on the figure. The two upper sands are partially water-bearing and are not exploited. The water-shut-off was thus made just above the lower oil sand, and the bottom of the hole was plugged back. Production was satisfactory, and the oil obtained was water-free.

(*d*) **Discovery of New Oil Sands.** It is common knowledge that pay sands are often missed by rotary drillers, and this for two reasons. Either a core was not taken or it was

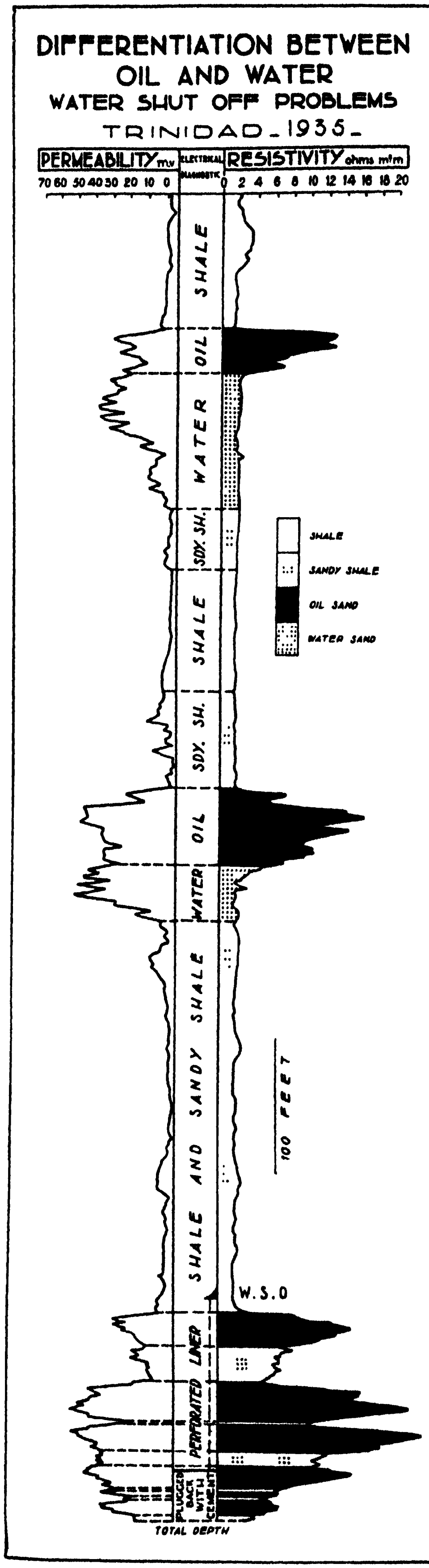


FIG. 11.

lost at the depth of the sand, or else the nature of the sand and oil were such that the core brought to the surface had completely lost its oil and appeared barren. The opposite can equally be true. The core, apparently rich in oil, belongs to a bed already invaded by water and unproductive from a practical standpoint.

To date, electrical coring must already be credited with the discovery of numerous otherwise unsuspected oil sands. Naturally, these sands are found mostly in the upper formations of the fields. If such a sand was once passed by during the exploration life of the field, the exploitation wells will continue to miss them, since they will be drilled

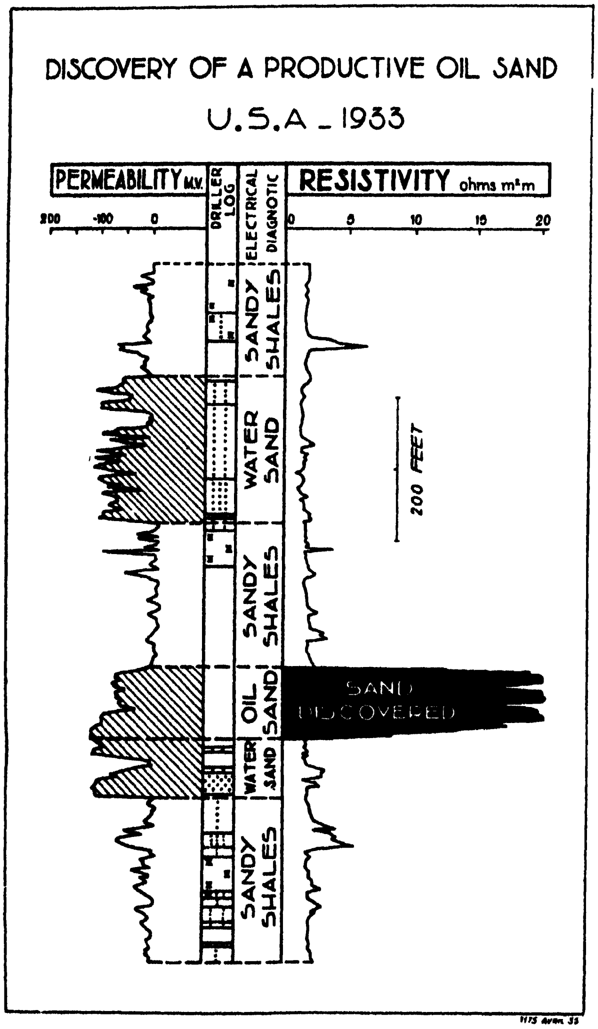


FIG. 12.

as rapidly as possible through what are believed to be unproductive horizons.

Fig. 12 is an example taken from the United States and Fig. 13 from Roumania. Thanks are due to Dr. Patriciu, Chief Geologist of the Credit Minier Company, who provided the data on the Viforata well. The two Meotic oil sands were passed by completely unnoticed, in spite of six cores having been attempted or taken in the neighbourhood, and even in one of the sands themselves.

(e) Relation between the Resistivity and the Productivity. Oil sands would show an infinite resistivity if the pores of the sands were entirely filled with pure oil. In reality, this resistivity is often not above a few ohms. This is due to the presence of films of water which, by capillarity, surround the grains of sand and establish a conductive network allowing the circulation of the electric current. It can easily be understood that, when the degree of oil impregnation and the pressure are high, the amount of capillary water is small and hence the resistivity is high.

Another factor must be mentioned in connexion with the above elementary principles. The logs give, as a general rule, the 'apparent resistivity', and no correction is made to determine the 'real' resistivity at a given distance from the hole. Therefore a low-pressure sand, more or less flooded by the water of the drilling-mud, will show up a low apparent resistivity. This electrical parameter therefore

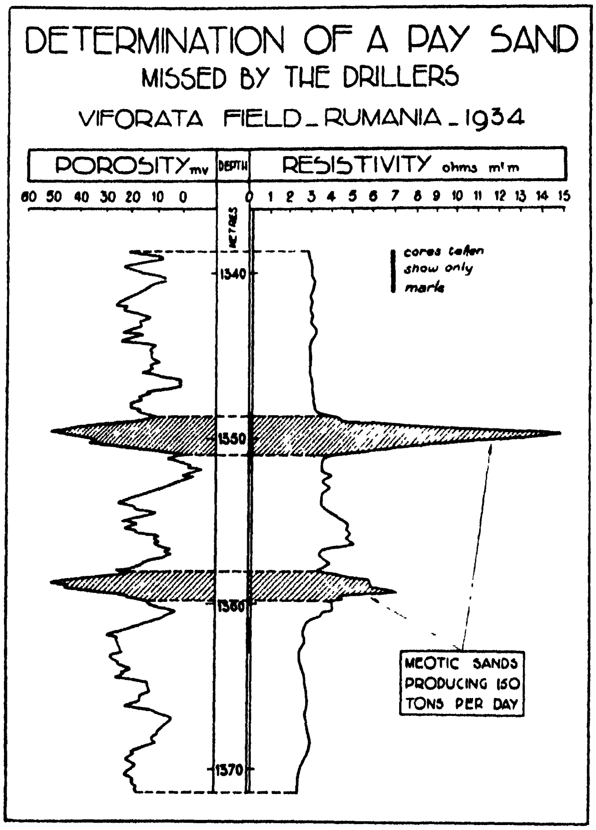


FIG. 13.

depends, to a certain extent, on the value of the pressure of the layers as opposed to the hydrostatic pressure of the mud, and a high rock-pressure is an indication of good productivity.

It should be clearly understood, therefore, on the basis of the above complex theory, that an absolute correspondence can never exist between resistivity and productivity. But, on the other hand, there is often a close relationship between these for a given layer in a certain field. The following examples show this clearly:

Fig. 14 shows five wells of a Venezuelan field. It is a good example of correlation, and it also shows how the resistivity of an oil sand decreases when moving from up-structure (well (*a*)) down the flanks into the edge-water (well (*e*)). The productivity follows a similar law.

Fig. 15 shows the log of five wells drilled in the Dacic of the Gorgoteni field (Roumania). First of all, it should be noticed that the Drader sand, which is figured shaded-in, shows up as very permeable and also very resistant when well saturated. These logs give the detail of the sand, and it can be studied easily foot by foot; the central clay streak

is clearly seen. Under each log is marked the corresponding initial daily production in tons. Reading these figures from left to right, it is seen that the decrease in production from 320 to 0 tons corresponds to a parallel decrease in the mean resistivity of the bed. Furthermore, the last well but one on the right appears to be really productive only at the base of the sand, and the very last one shows a permeable but non-resistant zone, which is a proof of sands without oil. often give very exact information as to the position of edge-water and as to its encroachment within the oil sands during their exploitation. This information is particularly useful in guiding the petroleum engineer in the case of several neighbouring but distinct sands, which may be exploited either together or separately, and in which the water-table does not necessarily rise in the same manner. The following example is given by Mr. Denissevitch (Azerbaidjan

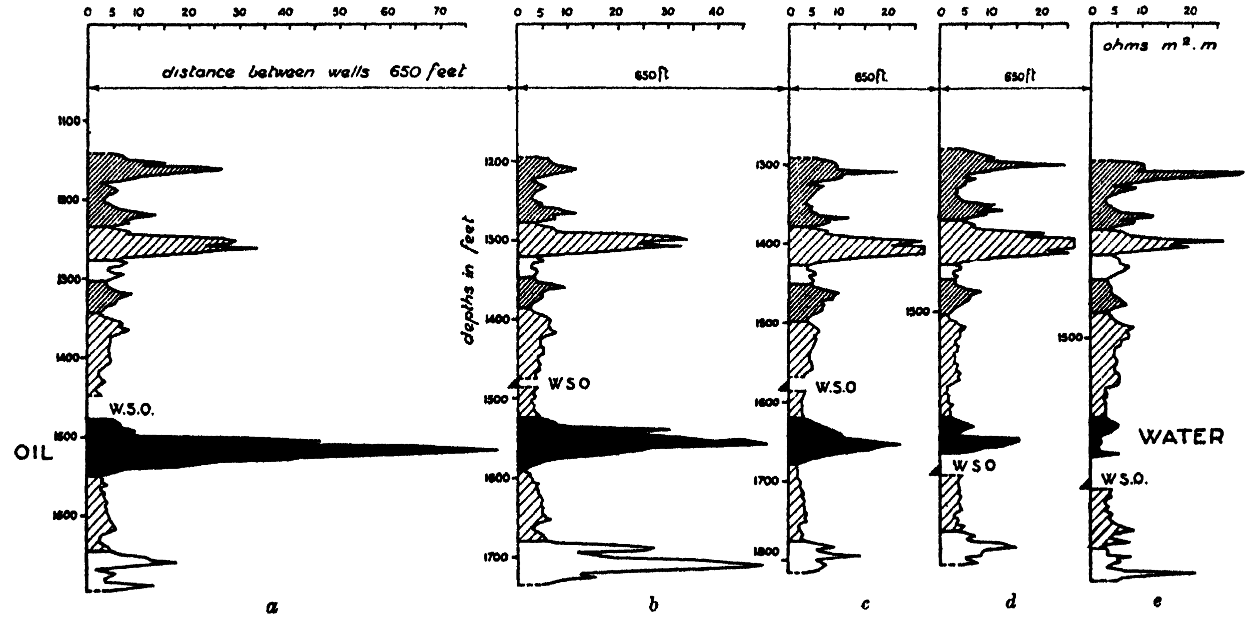


FIG. 14. Transition of a good producing sand into a water sand—Venezuela, 1930–1.

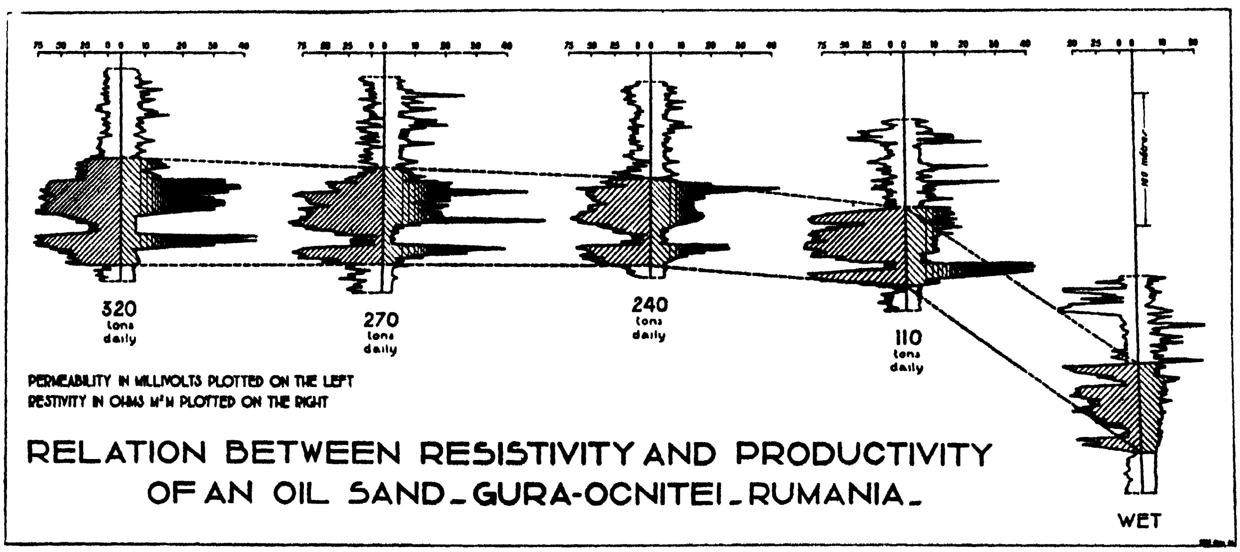


FIG. 15.

The parallelism between productivity and resistivity has been very widely used in the U.S.S.R. to draw horizon maps giving the value of the product of the thickness of the sand by its mean resistivity. Such a map is drawn in order to foresee the probable productivity of different wells exploiting the layer under consideration and to determine the spacing between the wells. It is in the form of a resistivity map with 'equi-resistivity' curves. These curves often cover the entire structure and define the position of the edge-water correctly.

(*f*) **Study of Edge-water.** Electrical resistivity diagrams

Petroleum Industry, November/December 1934). It concerns three layers called N.K.P. in the Sourakhany field at Baku. Fig. 16 shows a cross-section of the structure at successive periods of the life of the field; the resistivity logs of the sands are shown, together with their dates and the numbers of the wells.

Section (*a*) gives the assumed position of the water in September 1933, as well as the resistivity logs prior to this date. On the south-west flank the level of the water corresponds remarkably with the indication of the log of well 179. Section (*b*) shows the situation in February 1934. A new

well on the south-west (No. 668) shows that the two lower layers are flooded and that only the upper layer contains some oil at its top. Section (*c*) shows the situation in September 1934. On the south-west flank, the water encroaches regularly in the three layers. On the contrary, to the north-east a marked irregularity is to be noticed. The water has risen higher in the upper sand than in the other two (wells 571 and 724). Lower down, in well 719, the middle layer still contains oil, whereas the two others are flooded; it will therefore be difficult to recover this oil.

electromagnetic teleclinometer with an induction compass and a magnetic pendulum. This apparatus, which can only be used in the uncased part of a hole, has already been proved to be reliable by actual performance during several years [2].

3. Determination of the direction of formation-dips. This instrument is based on the ellipsoidal shape of the equipotential surfaces produced in anisotropic strata by electrical current flowing from a point electrode. This 'dip-meter' can be used at any depth [2].

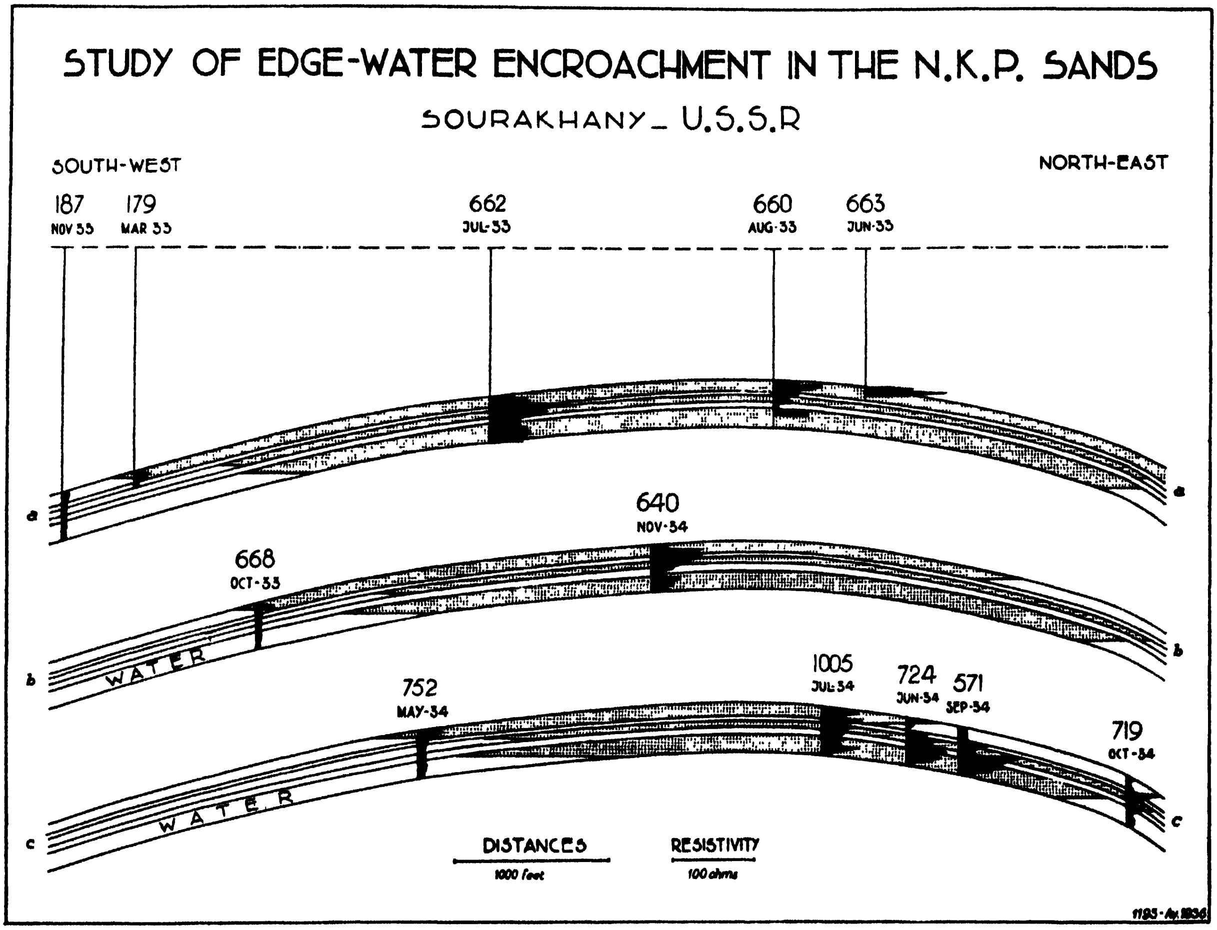


FIG. 16.

V. SUPPLEMENTARY OPERATIONS

Electrical coring operations (resistivity and permeability) can be completed by other geophysical measurements, using the same surface equipment (winch, cable, recording-potentiometer), but with special instruments lowered into the hole on the end of the cable. These supplementary operations cannot be fully described in the present article, and we shall discuss them only very briefly.

1. Continuous temperature logs inside a well. The electrical thermometer suspended at the end of the cable is of the resistance type. It is correct to a tenth of a degree centigrade and assumes the temperature of the surrounding mud or water quickly enough to allow a running speed of 15 cm. per second. These logs solve a number of problems, such as measurement of thermal conductivity of the different formations, location of water-flows, determination of the height of the cement behind the casing, &c.

2. Directional survey of crooked holes, by means of an

4. Many minor operations such as, location of the separation between oil and water in a well which is standing, search for pieces of metal lost in the walls of a hole, exact determination of the casing-shoe, perforation of the casing, &c.

VI. CONCLUSIONS

A summary of the principles of electrical coring and its major applications have been given. These methods may still be improved considerably as to many details, and for this purpose, further experiments are being made continually. It may, therefore, be hoped that electrical diagnosis will become more and more accurate and reliable, especially as to identification of the fluids absorbed by a permeable layer (oil, gas, or water). The adoption of drilling-muds specially suited for electrical processes (high resistivity, low viscosity, adequate colloidal properties) will undoubtedly improve matters considerably.

A few words may be added about the economic side of electrical coring. The process is very rapid, especially for the study of a deep open hole. It is also cheap, as the cost of an entire run corresponds to that of but a few metres drilled and a very few metres cored mechanically, this being particularly true for deep wells.

When electrical coring is introduced into a new oil region, it is necessary to compare it with the information already available from mechanical coring. In such a case it is undoubtedly an extra expense which, to the layman, may sometimes seem a useless luxury.

After this first stage and if, as is usually the case, geological conditions are favourable, it will be found that the results of electrical coring are at least as reliable as those of mechanical coring. When this occurs, the amount of mechanical coring is greatly reduced, and sometimes even abolished altogether (U.S.S.R.). This results in a great economy, and removes the drawbacks of mechanical coring (waste of time, poor recovery or total loss of cores, fishing jobs). The value of electrical coring is then unquestionable.

This economic aspect of the question, which it is easy to estimate in any given case, is not, however, the greatest advantage of electrical coring. The essential point is that, owing to the continuous logs, new facts are always available which may change the entire development of a field. These facts are: (1) The existence of electrical markers, invisible from cores, which enables structural maps in apparently homogeneous series to be drawn. (2) The recognition of previously unsuspected faults, and, in general, the correct and detailed interpretation of the tectonics of a field. (3) Above all, the discovery of new oil horizons, which had been unknown before. Experience has shown that such discoveries are frequent, and have an economic value much greater than the mere reduction of expenses due to the abolishing of mechanical coring.

It is obvious that electrical coring should be applied very prudently and progressively in a new region, as the mistakes of too hurried an interpretation can have serious consequences. The most important points to bear in mind are therefore: the quality of the measurements and the accuracy of the interpretation, that is to say, good equipment and experienced operators, even if such do cost a little more.

Except in limestone fields where few studies have as yet been made, it may be said that wherever electrical coring has been introduced, it has come to be used progressively in most of the rotary holes, and has thus become part of the routine of exploitation. Such has been the case for Venezuela, U.S.S.R., and Roumania. To-day this method is becoming more and more widely used in the U.S.A. The only exceptions to date are those fields whose geology is extremely simple, and those where the examination of cuttings (micro-fossils and characteristic lithological debris) enable one to follow up the stratigraphical horizons during drilling, with great ease.

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GRAVITATIONAL METHODS OF PROSPECTING

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INTRODUCTION

THE possibility of the use of gravimetric surveys in the search for petroleum lies in the following circumstances:

1. In areas of unwarped, unfolded, unfaulted sediments the distribution of density tends to be constant horizontally, but to vary vertically, mostly in the direction of increase of density with depth.
2. Structural deformation raises or depresses rock of one density into a zone of another density.
3. Many of the resulting abnormalities in the subsurface distribution of density produce appreciable distortion of the gravitational field at the surface.
4. The appreciable anomalies can be mapped by instruments which are of high scientific precision and sensitivity, which can be used in rapid field surveys.
5. From the form of those anomalies, conclusions can be drawn in regard to the distribution of density in the subsurface.
6. Hence conclusions can be drawn in regard to the geologic structure of the area.
7. Many types of commercial oil deposits are found on types of structure which produce appreciable gravity anomalies.
8. The oilman, therefore, may indirectly hunt for commercial petroleum deposits by the petroleum geophysicist searching for the kind of gravitational anomalies which are produced by those structures on which deposits are likely to be found.

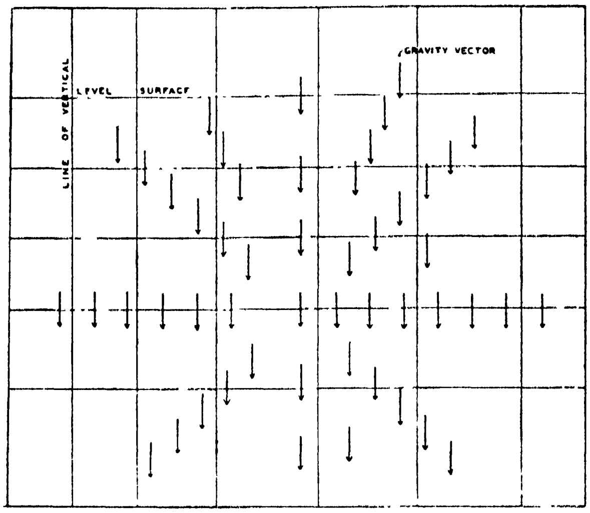


FIG. 1. Diagrammatic section through the gravitational field at the surface of a homogeneous earth with a flat surface. Vertical lines denote lines of the vertical, horizontal lines denote level surfaces; arrows indicate gravity vectors.

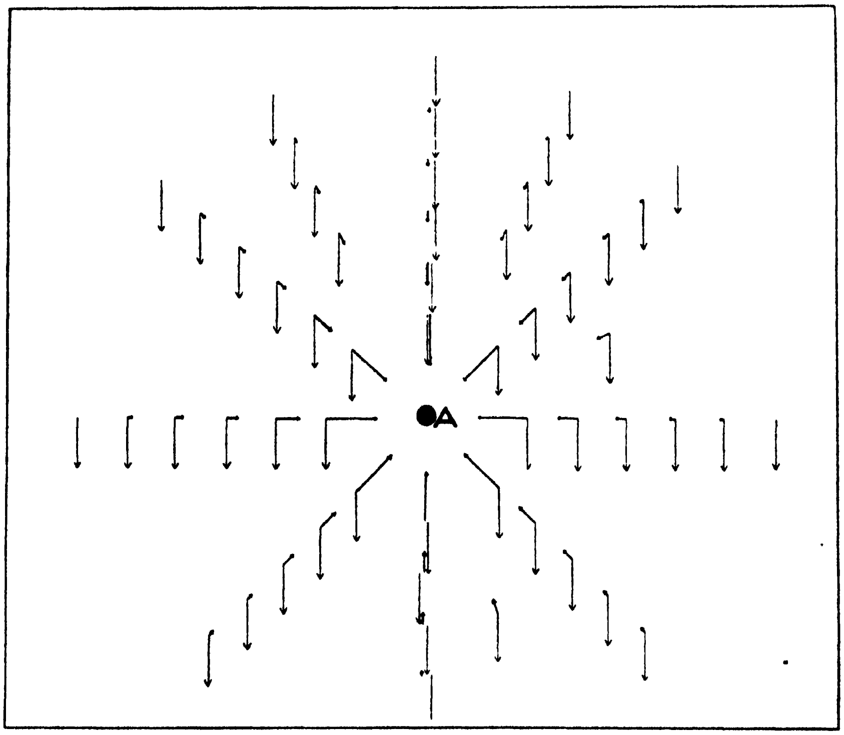


FIG. 2. A sketch of the field of Fig. 1 with a dense mass *A* added; diagonal arrows denote vectors of the gravitational attraction of *A*.

The petroleum geophysicist must first map the areal variations of the gravitational field at the surface. He must then consider the anomalies in his map, by analysis and quantitative calculations, by drawing on his geological knowledge and experience, and decide whether the indicated structures are likely to be in favour of the occurrence of commercial oil deposits.

MATHEMATICAL-PHYSICAL BASIS

A. Quantities Measured

Gravitational Field.

If the earth's crust were homogeneous, and if the earth's surface were perfectly flat, the lines of the vertical would be straight lines perpendicular to the earth's surface; and the level surfaces would be flat surfaces parallel to the earth's surface. (See Fig. 1.)

If a much denser body such as *A* in Fig. 2 is present in the otherwise homogeneous earth's crust of Fig. 1, it will set up its own gravitational field. Its attraction will be exerted radially towards itself, and the intensity of the attraction necessarily will vary according to Newton's law of the inverse square of the distance. The radial vector arrows of Fig. 2 represent the field gravitational attractions of the body *A*.

The actual total gravitational field will be the vectorial sum of the earth's gravitational field plus the field of body *A*. The vector of the actual gravity will be the sum of the vector of earth's gravity and the vector of the attraction by *A*. The resultant vectors are the ones shown in Fig. 3.

It should be remembered that the intensity of gravity at sea-level is slightly less than 980 gal.[1] (cm./sec.^{2}), and the intensity of very large structural anomalies is 0·050 gal. (cm./sec.^{2}). The ratio of gravity to the attraction of a body such as *A* in the earth's crust is distorted more than 20,000 times in Figs. 2, 3, and 4. The angular deviation of the resultant vector in Fig. 3 from the vector of earth's gravity actually is extremely minute.

The vector arrows of gravity are tangent to the lines of the vertical; and the latter, therefore, bend towards the body *A*.

The level surfaces necessarily, then, are tilted up and arch over the body.

If the density of *A* were less than normal, the vector arrows and the lines of the vertical would be deflected away from *A*, and the level surfaces would arch down above it.

Quantities used in Prospecting.

Three different components of the gravitational field of Fig. 3 are used in prospecting for oil: (1) the horizontal variation of the intensity of gravity; (2) the space rate of change of that horizontal variation of gravity; and (3) a quantity termed the differential curvature.

(1) Horizontal Variation of Gravity. If the gravitational field was wholly due to *A*, gravity would be represented by the radial vector arrows of Fig. 4 (and Fig. 3); but the direction of gravity in the composite system (field of attraction of *A* plus earth's gravitational field) will deviate only infinitesimally from the direction of the earth's gravity on account of the ratio 0·05 to 980 between the attraction of *A* and earth's gravity. The gravitational effect of *A* in contrast to its attractive effect, therefore, will be the vertical component of *A*'s attraction. Gravity at any point, therefore, will be the sum of the earth's gravity plus the vertical component of *A*'s attraction. The radial vectorial arrows and the accompanying heavy vertical component in Fig. 4 represent respectively (*a*) the gravitational attraction of body *A*, which is radially towards the body, and (*b*) the (anomalous) gravity of body *A*, which is the vertical component of its gravitational attraction. The curve of the variation of the anomalous gravity which is produced by body *A* is shown by the gravity profile in the middle part of Fig. 4. The anomalous gravity of the body *A* in any given level surface increases from zero at infinite horizontal distance to a maximum above the body. The form and amplitude of the gravity anomaly vary with the shape and the excess or deficiency of density of body *A* and its depth below the level surface

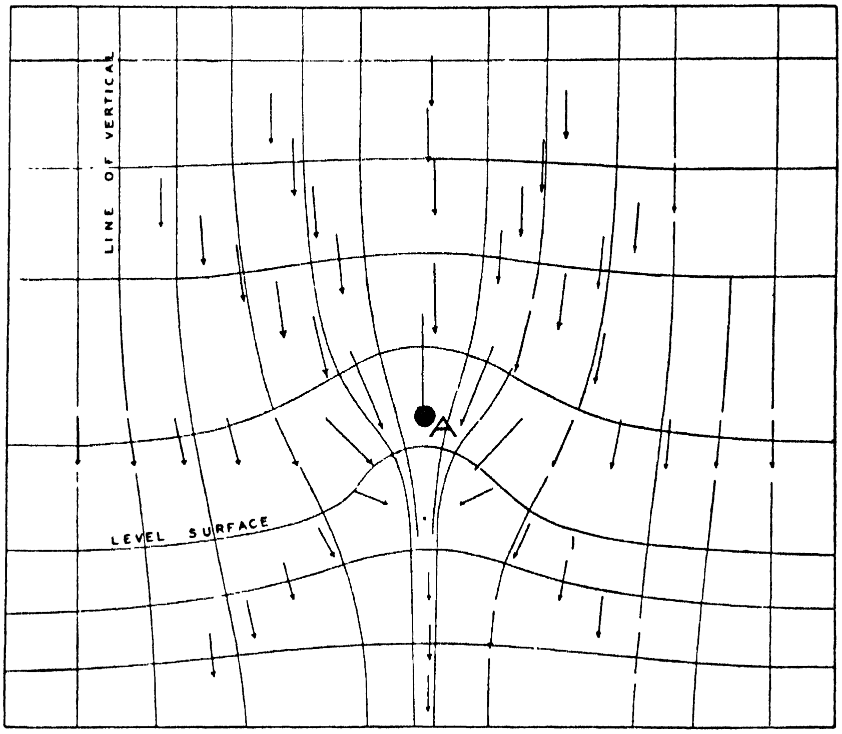


FIG. 3. The composite gravitational field. The arrows indicate the resultants of the two sets of vector arrows of Fig. 2. The warped vertical lines and a plane section of the level surfaces are also drawn.

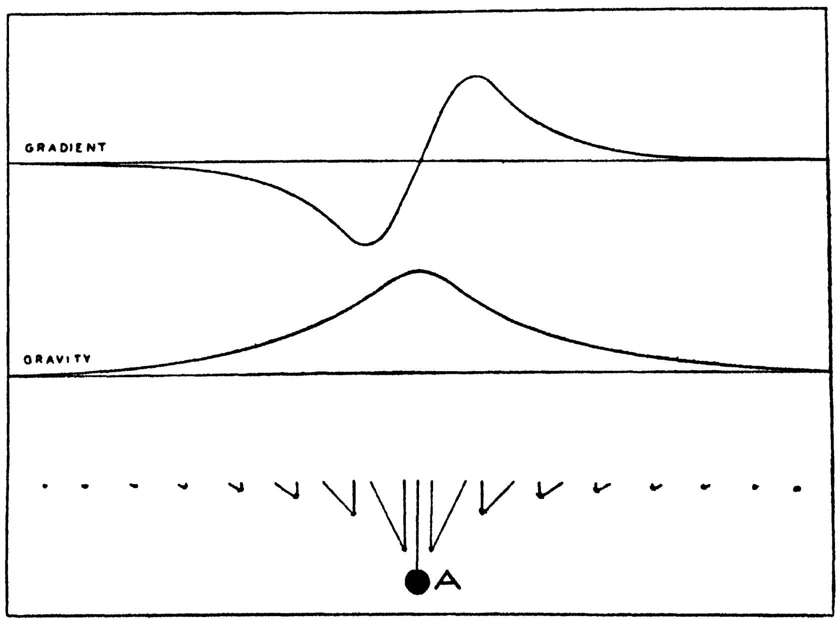


FIG. 4. Diagrams of the gravitational fields of Figs. 2 and 3. At the base is a line of vectors due to the attraction of the mass *A*; their vertical components are also drawn The curve in the middle shows the variations of those vertical components. The top curve plots the gradients of the middle curve and gives the space rate of change of the vertical components.

in which the value of gravity is observed, or to which it is referred.

The unit of measurement of the horizontal variation of gravity in prospecting is the milligal (0·001 cm./sec.^{2}) and tenth milligal, which are approximately the millionth and ten-millionth part of gravity at sea-level.

(2) **The Rate of the Horizontal Variation of Gravity or the Gradient.** The rate at which the gravity curve (Fig. 4) varies per horizontal centimetre is the gravity gradient (curve in upper part of Fig. 4) which is used in geophysical prospecting. It is the rate at which the vertical component of *A*'s attraction varies horizontally; it is the space rate at which gravity varies horizontally. There is also a corresponding vertical gradient, but the vertical gradient of *A*'s gravity is unimportant, and that of the earth's gravity is assumed to be constant, but a suitable correction is applied in surveys with the pendulum and gravimeter.

The unit of measurement of the gradient is 1×10^{-9} gal. per centimetre (cm./sec.^{2}/cm.), and is approximately the change of one-million-millionth of gravity at sea-level, per horizontal centimetre. It has been designated an 'Eötvös' unit, and is represented by the letter 'E'. The gradient is a vector, and is represented on maps by an arrow which flies in the direction of the maximum increase of gravity; its length is drawn to scale, most commonly 1 mm. equals 1 E.

(3) **Differential Curvature.**[2] The Eötvös curvature quantity is described by the following formula:

$$-g\left(\frac{1}{r_{\min}} - \frac{1}{r_{\max}}\right), \text{ and by an azimuth } \lambda, \quad (1)$$

in which g = intensity of gravity, $r_{\min}$ = minimum radius of curvature, and $r_{\max}$ = maximum radius of curvature of a level surface at the point of reference. The radius of curvature of an arc at any point is measured by the radius of the circle which fits the arc best at that point. The reciprocal of the radius of curvature decreases to zero as the curvature flattens to zero, and increases with the sharpness of curvature. The quantity $(1/r_{\min} - 1/r_{\max})$ is zero if there is no curvature of the level surface or if it is equal in all directions; this quantity increases as the curvature of the level surface increases in one direction and/or decreases (algebraically) in the perpendicular direction.

Geometrically, through the relation $(1/r_{\min} - 1/r_{\max})$ and the azimuth λ, the differential curvature gives the direction of greatest curvature (and necessarily the perpendicular direction of least curvature), and tells whether the curvature of the level surface in one principal direction is more than in the other major direction. It gives, however, no measure of the actual degree of curvature.

Any symmetrical differential warping of the level surface and the corresponding tilting of the vertical at each weight of a torsion balance gives gravity a small horizontal component at each weight, and thereby produces a torque which is proportional to the intensity of gravity as well as to the magnitude of the quantity $(1/r_{\min} - 1/r_{\max})$. The curvature quantity which the torsion balance measures, therefore, is

$$-g(1/r_{\min} - 1/r_{\max}).$$

The differential curvature is expressed in terms of a unit 1×10^{-12} cm.$^{-1}$. When this quantity is multiplied by g, the unit selected is (1×10^{-9} gal. per cm.) It must be remembered that the value of g is 980 gal. and for practical work this may be taken as 1,000, because the differential curvature $(1/r_{\min} - 1/r_{\max}$ is not observed with an accuracy of 2%.

On maps, the differential curvature is represented by a line whose direction is that of the axis of *algebraically* least curvature and whose length most commonly is drawn to the scale 1 mm. = 1 E (1×10^{-12} cm.$^{-1}$).

B. Measurement of the Three Quantities: Gradient, Differential Curvature, and Relative Gravity

I. Measurement by the Torsion Balance of the Gradient and the Differential Curvature.

Torsion Balance. The Eötvös torsion balance consists essentially (Fig. 5) of a carefully prepared and calibrated, very thin platinum-iridium (or tungsten) torsion wire (1),

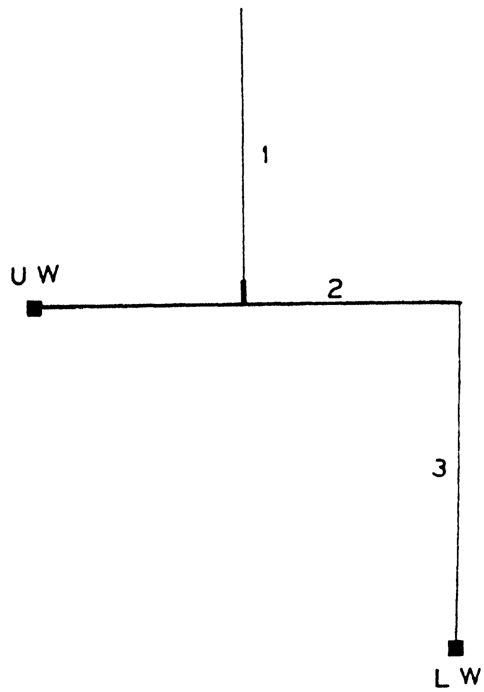


FIG. 5. Ideal sketch of the swinging system of an Eötvös torsion balance: (1) torsion wire; (2) aluminium beam, assumed to be of negligible weight; (3) lower suspension wire; *UW* and *LW*, upper and lower weights.

from which is suspended an aluminium bar of negligible weight (2). A gold or platinum weight (*UW*) is fastened to one end of the bar, and a similar weight (*LW*) is suspended by a fine wire (3) from the other end of the bar. A mirror is carried on the axial stem of the bar. Small horizontal rotation of the bar can be measured by the shift of the reflected image of scale against the vertical cross-hair in a telescope. The torsion wire resists rotation of the hanging system, and comes to rest when the resistance of the wire to torsion equals the torque affecting the swinging system. The torque necessary to rotate the swinging system per scale division is determined from the torsion coefficient of the torsion wire and from the dimensions of the instrument. If the swinging system is deflected by an unknown torque, its intensity can be determined by observation of the number of scale divisions and the multiplication of that number by the calibration constant for a scale division.

The deflection of the swinging system of an Eötvös torsion balance by the gravitational field depends upon the curvature of the level surfaces and of the lines of the vertical.

The relations of a torsion balance to the gravitational field in a very small section of space as in Fig. 3 are shown in a magnified form in Fig. 6. Within so small a region the level surfaces can be assumed to be parallel and to have a constant curvature; and similarly, the lines of the vertical may be assumed to be parallel and to have a constant curvature. The swinging system acts as a plumb-bob with its mass concentrated at the centre of gravity midway

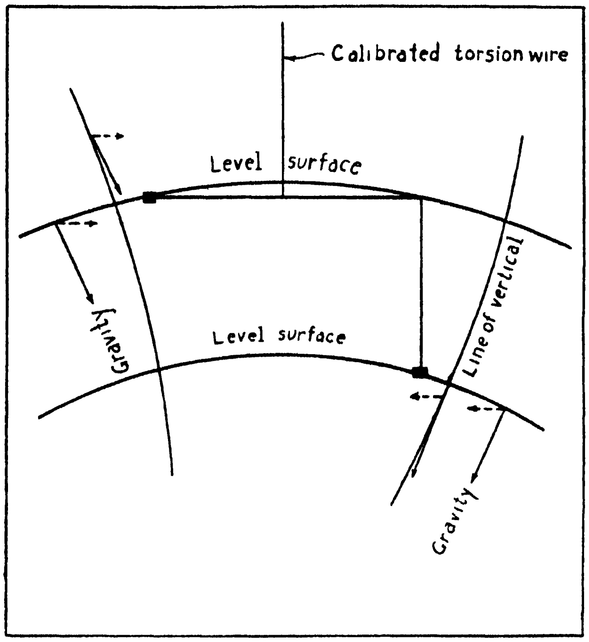


FIG. 6. The swinging system of a torsion balance in a very small space from the gravitational field of Fig. 3.

between the upper and lower weights, and comes to rest with the torsion wire in the straight line prolongation of vertical at that point. On account of the curvature of the level surfaces the directions of gravity at the two weights will no longer be parallel to the (vertical) axis of rotation of the swinging system, but will be warped symmetrically with reference to that axis. The curvature of the lines of the vertical produces similar warping symmetrically about the axis of rotation. The direction of gravity at each weight, therefore, is at an angle to that axis of rotation, and gravity has a horizontal component which produces a torque in the swinging system. Such horizontal components of gravity at the two weights in general do not lie in a radius of the swinging system of the torsion balance and, therefore, tend to rotate the swinging system. The intensity of the torque will be the resultant of two torques, the one a function of the curvature of the level surface, and the other a function of the curvature of the vertical.

Differential Curvature. The differential curvature is measured by the torsion balance as a function of the warping of the level surface.

The curvature of a level surface in the small space around a torsion balance is depicted in the block diagram of Fig. 7. The front face *ADFE* of the prism is assumed to be in the vertical plane of the maximum curvature, and the right face to be in the vertical plane of the minimum curvature of the level surface. The faces cut the level surface in the lines *h*, *k* of Fig. 7. One weight of the torsion balance is represented by *W*.

Gravity at *W* is directed diagonally downwards and in-

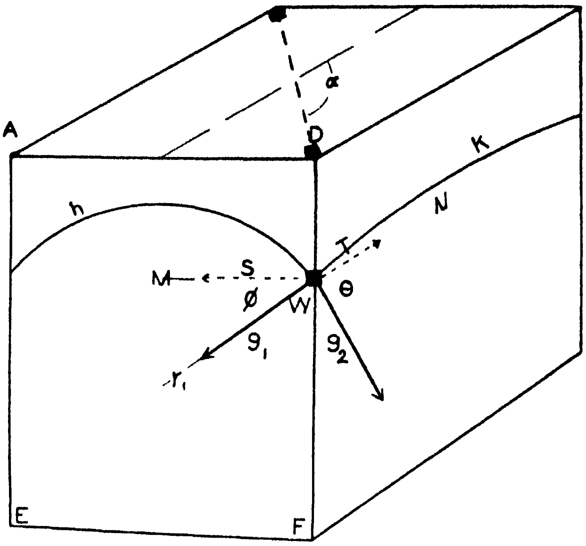


FIG. 7. Diagram representing a cube of space around a torsion balance and illustrating how warping of the level surfaces produces the Eötvös differential curvature effect.

wards at right angles to the level surface at *W*. The vector representing gravity will have a projection g_1 on the front face, and a projection g_2 on the right face. The vector g_1 has the horizontal component *S*, and g_2 the horizontal component *T*. If r_1 is the radius of curvature of *h* and r_2 of *k*, then[3] $\cos\phi = \dfrac{MW}{r_1}$, $\cos\theta = \dfrac{NW}{r_2}$, and $S = g_1\cos\phi = g_1\dfrac{MW}{r_1}$, and $T = g_2\cos\theta = g_2\dfrac{NW}{r_2}$. *MW* and *NW* are functions of the length (l) and azimuth α of the balance beam.

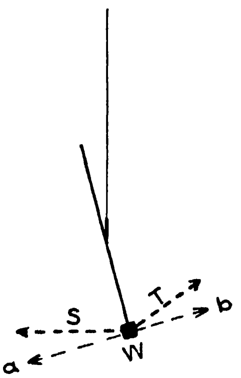


FIG. 8. Horizontal section through *W* of Fig. 7.

The force acting on the weight is a function of the difference between (*Wa*), the component of *S* perpendicular to the balance beam (Fig. 8), and (*Wb*), the component of *T* perpendicular to the balance beam, and, therefore, it is a function of gravity times the difference between the reciprocals of the maximum and minimum radii of curvature.

The value of the differential curvature is often denoted by the symbol *R* and its azimuth by λ (lambda). If the coordinates of reference are not parallel to the axes of curvature, the differential curvature has two components: U_Δ (less commonly U_{yy-xx}) which is used in place of its symbol[4] in the calculus $\left(\dfrac{\partial^2 U}{\partial y^2} - \dfrac{\partial^2 U}{\partial x^2}\right)$, and U_{xy} which is used in place of $\partial^2 U/\partial x \partial y$.

The relations between *R*, lambda, U_Δ, and U_{xy} are

$$R = \sqrt{(4U_{xy}^2 + U_\Delta^2)}, \qquad \lambda = \frac{-2U_{xy}}{U_\Delta}.$$

Gradient. The horizontal gradient of gravity is measured by the torsion balance as an effect of the curvature of the vertical.

Two vertical square centimetres, one above and one below the horizontal plane aa', through the centre of gravity of the swinging system of the torsion balance in Fig. 6, are represented in Fig. 9. Any line of gravity, V, necessarily is perpendicular to aa', but on account of its curvature makes an angle α, very close to 90 degrees, with bc and ed. If the value of gravity is g at a', it will be $(g+U_{xz})$ at c.

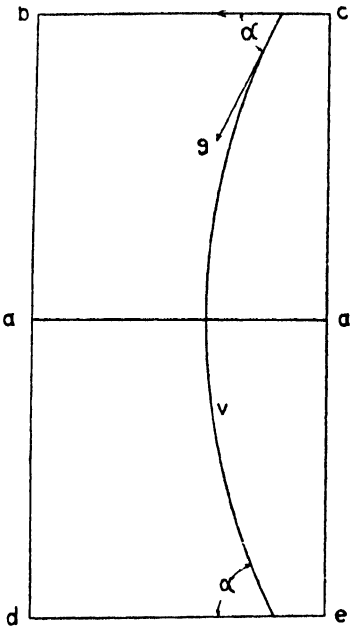


FIG. 9. This diagram represents two square centimetres, perpendicular to the plane of the level surface through the centre of gravity of the swing system of an Eötvös torsion balance; aa' is the plane of the level surface; V is a line of the vertical within the two squares; g is the vector of gravity at the intersection of V with bc.

The physical work of movement against gravity from one place to another, as, for example, from a to c, is independent of the route and will be the same via a' or b: i.e.

from a to b	g	from a' to c	$g+U_{xz}$
from b to c	$g\cos\alpha$	from a to a'	0

by addition, $g+g\cos\alpha = g+U_{xz}$

That is, the small horizontal component of gravity, $g\cos\alpha$, which is a function of the curvature of the vertical and which activates the torsion balance, is equal to the horizontal gradient of gravity U_{xz}.

The gradient is measured in its north-south and east-west components, which are known by the respective symbols U_{xz} and U_{yz}, contractions for the symbols $\partial^2U/\partial x\partial z$ and $\partial^2U/\partial y\partial z$ in the notation of the calculus. The gradient and its azimuth α are calculated from U_{xz} and U_{yz} by the formulae:

$$\text{gradient} = \sqrt{(U_{xz}^2+U_{yz}^2)} \quad \text{and} \quad \tan\alpha = \frac{U_{xz}}{U_{yz}}.$$

General Equation. The general equation which combines the effects of the differential curvature and the gradient on the Eötvös torsion balance can be shown by slightly longer consideration of those quantities to be

$$N-N_0 = \frac{K}{2}U_\Delta \sin 2\alpha + KU_{xy}\cos 2\alpha - MU_{xz}\sin\alpha + MU_{yz}\cos\alpha,$$

in which N = the scale reading, N_0 = zero-point scale reading (an unknown), K and M instrumental constants which depend on the torsion coefficient of the torsion wire, on the mass of the weights and on the horizontal and vertical distances between them; where α is the azimuth of the balance beam from north.

Five observations in different azimuths are necessary for the solution of the equation and the elimination of the five unknowns, N_0, U_Δ, U_{xy}, U_{xz}, U_{yz}. This is true if a single beam instrument is used, or if independent determination of those quantities by each of the two beams of the modern instruments is desired.

Six values of that equation by observations with the modern double-beam instrument in three positions (normally 120 degrees apart). This is sufficient for the solution of the six unknowns of the equation as applied to double-beam instruments. In such instruments the N_0 of the preceding equation is replaced by N_0' for beam I, and N'' for beam II.

Observations at azimuths of 0 and 180 degrees (or 90 and 270 degrees) will give the values of U_{xz} or U_{yz}.

Observations at azimuths of 0, 180, 90, and 270 degrees will give U_{xz}, U_{yz}, and U_Δ. Observations at azimuths of 45, 135, 225, and 315 degrees will evaluate U_{xy} and the two components of the gradient.

Field Observations. A site is chosen which preferably is plane within a radius of 5 metres from the instrument, and has a slope of less than 2 degrees. The station should not be near any hill or mountain with more than 5 degrees of elevation, or any valley exceeding 5 degrees of depression. Bedrock is better than alluvial fill for a site, which, if rough, should be smoothed artificially to a distance of 3, 4, or 5 metres.

The instrument is set up in an insulated portable shelter.

With the visual instruments, an observer has to read the instrument and turn it into the next position at stated intervals until he has a satisfactory series of readings.

With the automatic instruments, the observer sets the instrument for a stated number of readings at the correct intervals of time and azimuth, and then leaves it to make automatic photographic readings and to turn itself at the end of each interval, and he returns only after the end of the run. If the series of readings is unsatisfactory, a complete new run has to be made.

The time necessary for a complete observation at a station in a survey in which good accuracy is desired ranges from 5 hours for one of the large instruments, which takes 50 minutes to come to rest, to slightly over an hour for the shortest period instruments; and is slightly under 4 hours for the instruments in most common use. These figures envisage at least five readings in 120-degree positions, and a moderate but not extreme range of temperature.

Under the average conditions in the Gulf Coast of Texas and Louisiana, other than in the swamps, it is usual to complete observations at three or four stations each day. The rate depends, however, upon a considerable number of factors: the type of instrument and its condition, the conditions of terrain, the distance between stations, the precision desired in the observations and the policy of more stations per instrument, or of more stations per observer. In common practice, no difference exists between the rate of observation with visual instruments and that with automatic instruments.

In practical accuracy, no difference exists between the visual and the automatic instruments.

II. Measurement of Gravity.

Relative Gravity. The absolute value of gravity can be measured, but on account of the great difficulty of securing good accuracy, observations of it are made only at a few central geodetic observatories of the world. The geophysical prospector, however, is not interested in the absolute value of gravity, but in the local variations of its intensity, which are produced by such local subsurface irregularities of mass as body A in Fig. 2.

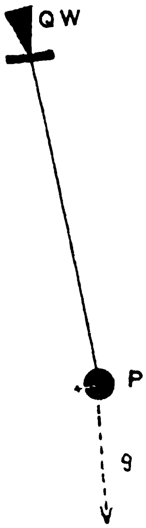


FIG. 10. Ideal sketch of a gravity pendulum: QW is the quartz knife-edge support; PB is the pendulum bob; g the vector of gravity.

Relative gravity, the value of gravity at any station in reference to the known or assumed value of gravity at some base station, is measured directly with fair ease and accuracy: (1) by the invariable pendulum; and (2) by static gravimeters of several different types; its value can also be calculated from the results of a series of torsion-balance observations between the stations.

By Pendulum. The rate of swing of a pendulum depends on the intensity of gravity and on the length, shape, and mass distribution of the pendulum (Fig. 10). The greater the value of gravity the more oscillations per minute by the pendulum, the faster is the rate of swing and the shorter is the period P of the swing. If a pendulum of constant length is swung at two different stations, the periods of swing at the two stations are inversely proportional to the square roots of the respective intensities of gravity, that is, for two stations a and b,

$$\frac{P_b}{P_a} = \sqrt{\frac{g_a}{g_b}};$$

and if x is any field station, and b is the base station,

$$g_x = P_b^2 \cdot g_b \cdot \frac{1}{P_x^2}.$$

Corrections have to be applied, for it is impossible to make the conditions under which the pendulums are swung exactly the same at all stations, and small changes in the temperature of the pendulum, in the air pressure within the pendulum case, &c., produce serious effects. Corrections, therefore, have to be applied for the effects of the differences of conditions.

The period of swing of the pendulum has to be determined with high precision, for an error of 0·00000005 sec. in the period corresponds to an error of one-tenth milligal in the determinations of the value of gravity.

The period of swing of the pendulum is determined by so-called 'coincidence' observations. In the standard method of observations by such institutions as the United States Coast and Geodetic Survey, the swing of a pendulum is compared with the beat of a chronometer. A coincidence determination consists of the observation and calculation of the times when the beat of the pendulum and that of the chronometer are coincident. In the interval between two coincidences a half-second pendulum makes one oscillation less (or more) than twice the number of seconds ticked off by the chronometer. The average value of the coincidence interval is determined by observing three or four coincidences when the pendulum is first started, and three or more at the end of the observation period. The chronometer has to be checked daily against wireless time signals from some such observatory as the United States Naval Observatory.

In precise pendulum surveys by oil companies, coincidence observations are taken between the oscillations of the pendulum at the base and those at the field station. The beats of the pendulum at the base station are sent out from a portable wireless sending station, are received at each field station and recorded photographically on the same strip of film as are the beats of the pendulums at the receiving stations. The coincidence interval, therefore, can be determined much more rapidly and accurately than in coincidence observations with chronometers.

A primary base station is chosen and all values of gravity in that general area are referred to it. But in surveys of local areas, a sub-base station may be chosen, or any station at which the value of relative gravity has already been established may be used as a temporary base station.

Less accurate pendulum surveys of the value of gravity at sea can be made with a special apparatus which was designed by Dr. F. A. Vening-Meinesz of the Dutch Geodetic Commission. The observations are made in a submarine. The apparatus is hung in a cradle in gimbals. Continuous photographic registration on the same film is made of all the oscillations of the several pendulums. From the interrelation of the oscillations of the different pendulums the effects of the unstable and moving foundation can be computed out, and the value of gravity can be determined with fair accuracy.

The accuracy of determinations of relative gravity with the pendulum is approximately as follows:

	Probable error in tenth milligal
Meinesz' determinations at sea . . .	± 30 to ± 50
Standard, Geodetic Survey determinations .	± 10
Best commercially purchasable pendulums .	± 5
Specially built or rebuilt company pendulums .	± 2 to ± 3

The rate of observation is one to four stations per day.

Observations of relative gravity with probable error[5] ± 5 tenth milligal or better is extremely difficult, and any one who attempts to attain and maintain observations with such accuracy will expect trouble.

Determinations of relative gravity with a probable error of ± 10 or even ± 5 tenth milligal are of value in geophysical prospecting only in broadly depicting large regional features or abnormally large local anomalies. The amplitude of the effects due to structural anomalies with which the petroleum geophysicist works is not as large as 50 tenth milligal, and may not be as large as 15 tenth milligal. Errors three times the probable error should be common according to theory. Determinations with a probable error of ± 5 tenth milligal, therefore, may have an error larger than the value in which the geophysicist is interested.

By Gravimeters. Several static gravimeters, of similar type, are in moderate commercial use. Most depend on the principle of the differential compression-extension of a spring by a constant mass under different intensities of gravity (Fig. 11). The greater the value of gravity, the more the supporting spring is compressed and the suspending spring extended. Slight vertical movement of the heavy mass is observed visually by an appropriate optical system. The instrument is calibrated in terms of scale divisions by determining the change of mass which is necessary to produce a vertical deflexion of one scale division. If the instrument is then read successively at two

different stations, the difference between the scale readings multiplied by the scale coefficient gives the value of relative gravity between the stations.

Observation with gravimeters is simple and speedy. The instruments can be permanently mounted in a truck, and 5 to 10 minutes suffices for the complete measurements at a station; but, unfortunately, gravimeters are erratic, and it may be necessary to repeat visits to stations in order to attain fair precision.

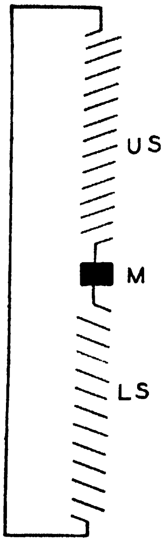


FIG. 11. A generalized, ideal sketch of some types of spring gravimeters; *US* and *LS* denote the upper and lower springs, *M* the heavy mass.

A probable error of ± 3 tenth milligal has been obtained in surveys with the gravimeter, but it is a question in the writer's mind whether any gravimeter maintains that accuracy at all times. Few gravimeters attain it at any time.

A gravimeter is as temperamental as an aneroid bariometer, or a magnetometer, and in many ways surveys with a gravimeter have to be handled similarly to those with the aneroid or magnetometer.

Several other types of gravimeters working on different principles are coming into use.

Torsion Balance. The variation of gravity between two places can be calculated if the gradient profile between them is known, for the gradient is the horizontal variation per centimetre, and, therefore, the distance in centimetres times the gradient gives the difference in gravity. If torsion-balance stations are close enough together, the gradient profile may be determined, and the value of relative gravity may be calculated for all points of the profile.

The variations of gravity are usually calculated and next lines of equal intensity, or isogams,[6] are drawn; for it is easier to interpret such a map than one covered with arrows or vectors. Stations are not close enough together to draw the curves with any precision, and the values calculated by different routes between two key stations often differ considerably, so that adjustments are unavoidable. Large-scale commercial surveys are frequently being extended, and new work must be blended with old. Such extension demands both experience and skill.

The accuracy of the determination of relative gravity in good torsion-balance surveys, in fair terrain, according to the writer's calculations, is of the general magnitude of $\pm 2{\cdot}5$ to $\pm 4{\cdot}8$ tenth milligal. per $\sqrt{\frac{d}{10}}$ km., where d is the distance in kilometres.

C. Extraneous Effects and the Reduction of Observations

Extraneous Effects. The crude values of the gradient, of the differential curvature, and of relative gravity which are determined by the instrument are not directly of use to the geophysicist. These include other effects of appreciable magnitude, in which the prospector is not interested. Values observed with the torsion balance are the sum of: the effect of irregularities of topography; the effect of soil and subsoil irregularities of density; the effects of structural irregularities of density of several different orders; the latitude effect. Values obtained with the pendulum or gravimeter are the sum of: the effect of elevation above sea-level; the effect of the shell of sediments between sea-level and the level of the station; the latitude effect; the effect of very large topographic features; and of structural irregularities of density of several different orders. By the application of the proper corrections the observed values can be reduced to those which are chiefly the composite effect of irregularities of density in the earth's crust.

Topographic Effect. The effect of topography on the gradient and differential curvature in general is of the same general magnitude as the structural effect. A plane slope of 1 degree over a radius of a thousand metres, for example, produces a gradient of 14 E.

Correction of the observed gradient and differential curvature for the effect of the topography, therefore, is a part of the routine of observation of every station. Levels are run as part of the routine, out to 20, 50, 100, or 200 metres from the instrument, according to the relief; and the correction is calculated by routine formulae. Correction for the topography beyond 200 metres is rarely attempted in commercial surveys, but can be made if a topographic map of the area is available.

The gradient effect of topography is at a maximum for excesses or deficiencies of mass within the zone 40 to 60 degrees below or above the horizontal plane through the instrument, and is zero for irregularities of topography in the same horizontal plane as the instrument, or in the vertical axis of the instrument. The effect of topography within ± 2 degrees of the horizontal plane of the instrument is negligible, and within ± 5 degrees is slight.

The differential curvature effect of topography is at a maximum in the horizontal plane and in the vertical axis of the instrument.

Too great topographic relief excludes the use of the torsion balance in most prospecting for oil, for the cost of obtaining sufficient topographic data and of making the calculations becomes prohibitive except for especially important surveys. The gravitational effects which are produced by rugged topography are in part the effects of subsoil irregularities of density, and therefore are not completely compensated by subtraction of the topographic effect. As the differential curvature is particularly sensitive, and the gradient particularly insensitive, to irregularities of mass in the horizontal plane of the instrument, the differential curvature is useless in mildly rugged topography in which the gradient is correctly found.

The gravity effect of the irregularities of topography is small; the mass of the close-in topographic irregularities, which so profoundly affect the gradient and the differential curvature, is so very small that the effect on relative gravity is negligible, and, furthermore, according to the law of its variation the gravity effect varies as the sine of the angle above or below the plane of the horizontal; and correction for topography is not made in the determinations of relative gravity in commercial surveys in regions of low or moderate relief. The geodesist who is interested in isostasy routinely makes a correction even for low or moderate topography. But the faint broad anomalies which regional topography might produce do not seriously distort the sharper and areally smaller structural anomalies. The calculation of the topographic correction is tedious. The petroleum geophysicist, therefore, normally neglects the very faint effect of the regional topography in areas of low or moderate relief.

Elevation Correction. The intensity of gravity decreases vertically upward at the rate of 3·08 tenth milligal. per metre. All determinations of gravity in geophysical prospecting, therefore, normally are reduced to the level of the base station of the particular survey.

The reduction is made by two different methods. In the 'Free Air' method the shell of space between the level of the station and the datum level is assumed to be composed wholly of air (i.e. 'Free Air') and to have no gravitational effect. In the Bouguer method, that shell of space is assumed to be composed of rock of some definite specific gravity, and allowance is made for its gravitational effect.

The 'Free Air' correction, therefore, is equal to $\frac{2h}{R} \times g$, in which h is the height of the place of measurement above the sea-level, and R the radius of the earth for the latitude under consideration. Since the influence of the latitude is very small, the quantity $2g/R$ (assuming the earth to be a sphere) is a constant term and can be taken as 0·0003086, according to Helmert, for almost every latitude. Hence the 'Free Air' correction is $+3{\cdot}08 \times h$ tenth milligal, where h is the difference of elevation in metres. The Bouguer correction includes the ratio of the density d of the assumed rock of definite specific gravity and the mean density of the earth:

$$3{\cdot}08 \times h \times \left(1 - \frac{3d}{22}\right)$$

$= 2{\cdot}05$ to $2{\cdot}15$ tenth milligal. per metre.

Reduction with allowance for isostatic compensation is made by many geodesists, but not by petroleum geophysicists.

No comparable reduction is necessary for the quantities measured by the Eötvös torsion balance. The 'Free Air' and Bouguer reductions compensate the vertical variation of gravity. The horizontal variation of gravity and of the curvature of the level surfaces, however, are the same for all level surfaces in the narrow vertical range of elevation within which it is practicable to make surveys with the torsion balance, except with reference to masses which are very close to the surface.

Latitude Correction. The intensity of gravity at sea-level increases from a minimum at the equator to a maximum at the poles according to the formula:

$$g_\phi = g_{\text{equator}}\,(1 + 0{\cdot}0053 \sin^2\phi - 0{\cdot}000007 \sin^2 2\phi).$$

The variations in latitudes between 0 and 30 degrees are: gravity, 7 tenth milligal. per kilometre; and gradient, 7 E. The latitude variation of gravity is produced because the earth is a rotating oblate spheroid flattened at the poles. The magnitude of that variation is of the same general order as that of the structural anomalies. Direct determinations of relative gravity in geophysical prospecting, therefore, are reduced to the latitude of the base station; and a normal correction is applied in the routine of the calculations of the gradient and differential curvature.

D. Mathematical Interpretation

The form, depth, and density of the subsurface body which is producing an observed anomaly can be determined within certain limits from the form and amplitude of the anomaly.

A unique solution cannot be obtained in practice. Certain limits in general can be set between which there exists a continuous series of possible solutions. Those limits are relatively close together if the depth to the body is approximately the same, or less than, the vertical thickness of the body. Those limits become progressively farther apart as the depth becomes greater than the vertical thickness of the body, and very little can be told about a body which lies at a depth great in comparison to its vertical thickness. The limits are closer together if the relative density relations are known, and yet closer if one or two points on the surface of the body are known.

Most structures of the petroliferous types resemble approximately some one of the following geometrically simple bodies: A, infinite steps; B, horizontal tabular prisms; C, triangular prisms, apices up; and D, triangular prisms, apices down (see Fig. 12).

A horizontal plate, infinite in all horizontal directions, produces an effect on the absolute value of gravity, but does not affect the relative gravity, the gradient, or the differential curvature. The presence of such an infinite horizontal plate, tangent to the top or bottom of one of the primary bodies of Fig. 12, therefore, does not affect relative gravity, the gradient, or the differential curvature. The correlative forms of Fig. 12, therefore, produce anomalies identical with those of the respectively corresponding primary forms.

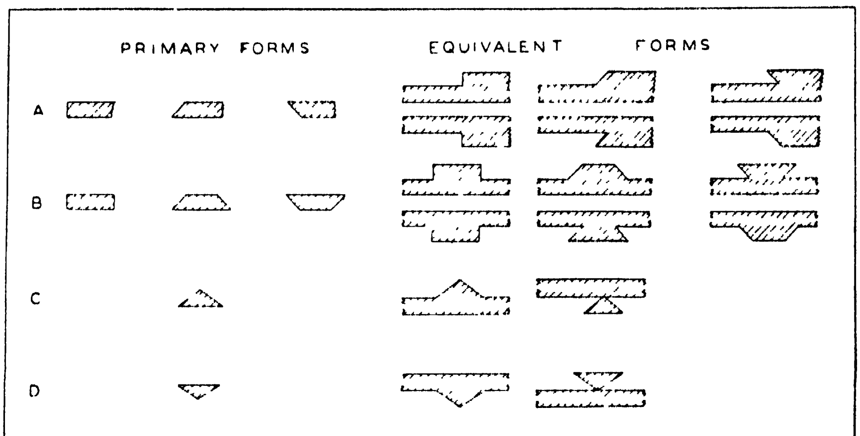


FIG. 12. Bodies of geometrically simple cross-section, which correspond to many common types of geologic structure.

Each one of the forms of Fig. 12 may be at shallow, medium, or great depth in comparison to the vertical dimension of the anomalous body.

The gradient, relative gravity, and differential curvature anomalies which are produced by such simple forms are shown in Fig. 13.

Change of the algebraic sign of the density of a body relative to its surroundings turns the anomaly upside down, but does not change its form.

Variation of the relative density of a body changes the amplitude but not the form of the corresponding anomaly; and by corresponding inverse change of the scale at which the gradient is plotted, the gradient profile can be held constant, although the relative density is changed.

The sign of the relative density of the causative body is shown by the sign of the anomaly. A gravity minimum is found over a body which is lighter, and a gravity

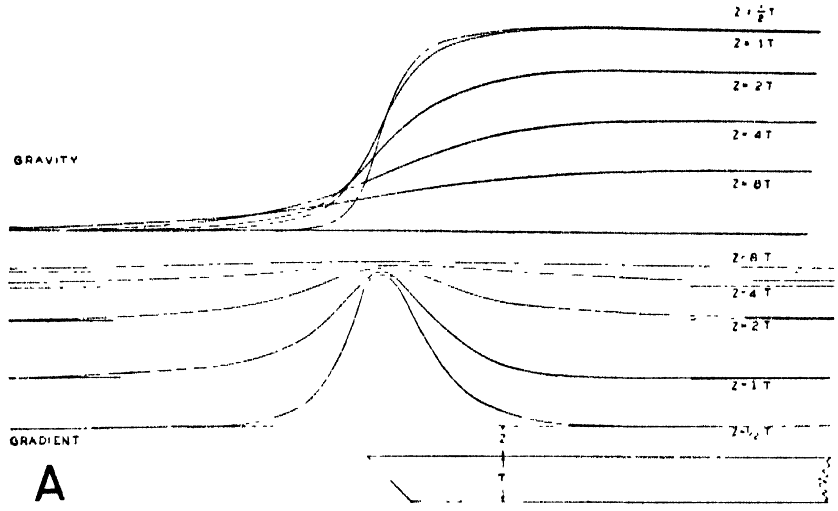
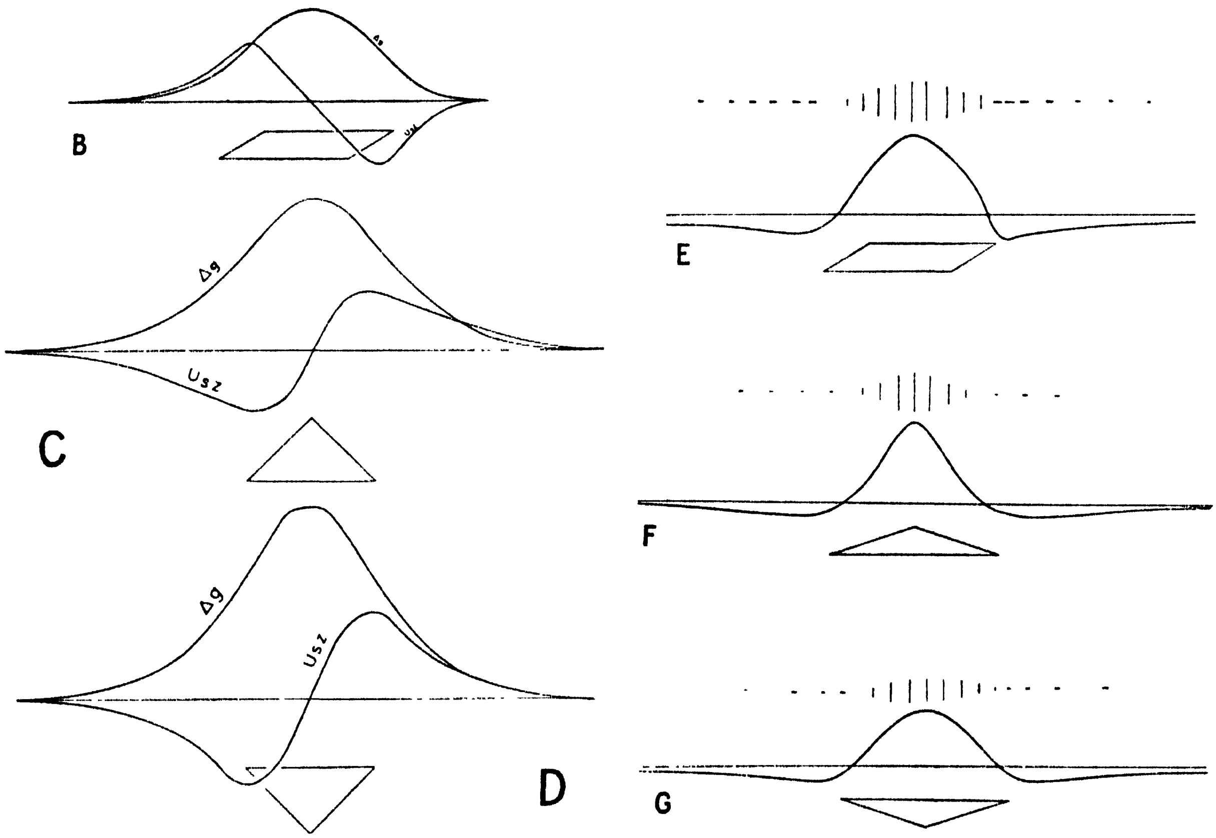


FIG. 13. Gradient, Gravity, and Differential Curvature anomalies of bodies of the types in Fig. 12.
A. Gravity (upper) and gradient (lower) profiles for an infinite step-block of thickness *T*, at depths respectively ½, 1, 2, 4, and 8 times that thickness.
B. Gravity and gradient profiles for a plate-like prism.
C. Gravity and gradient profiles for a prism of triangular cross-section, base down.
D. Gravity and gradient profiles for a prism of triangular cross-section, apex down.
E. Map (above) and profile (below) of differential curvature for horizontal plate-like prism.
F. Map (above) and profile (below) of differential curvature for a prism of triangular cross-section, base down.
G. Map (above) and profile (below) of differential curvature for a prism of triangular cross-section, apex down.



maximum is found over a body which is heavier than the surrounding medium. The gradient seems, as it were, to be displaced from the relatively lighter mass towards the relatively heavier body. The differential curvature has the general pattern of —|— or —¦— over a finite body of positive relative density, and a pattern of |—| or ⊔ over one of negative relative density.

Primary Geometric Forms (Fig. 12). The magnitude of the relative density is not given definitely by the amplitude of the anomaly.

The approximate depth to the top of the body is given by the following two relations: (*a*) for fairly symmetrical anomalies of the type of *A*, Fig. 13, the distance on the ground between the two points at which the gradient is one-half of the maximum gradient is equal to twice the depth to the crest of the body; and (*b*) for anomalies of the type of *C* and *D*, Fig. 13, the horizontal distance between the two points of gradient maximum is equal to twice the depth to the crest of the body. For anomalies of the type of *B*, Fig. 13, rule (*b*) gives too great depth, and rule (*a*) must be used in connexion with either the right or left halves of the anomaly.

The form and dimensions of the causative body are indicated with varying degrees of vagueness by the form and dimensions of the anomaly. Bodies of type *A*, Fig. 12, are definitely distinguishable from those of types *B*, *C*, and

D by the difference in the respective types of anomalies. Bodies of type *B* are recognizable from those of types *C* and *D* unless the depth of the bodies is great in reference to the vertical thickness of the bodies. But it can be seen that the relative gravity anomaly does not show the difference as clearly as do the gradient and differential curvature anomalies.

Bodies of type *C*, Fig. 12, are recognizable from those of type *D* by the difference of the respective anomalies, if the depth to the bodies is slight, but the difference between the respective types of anomalies disappears if the depth to the bodies is moderate. The difference is much harder to distinguish in the relative gravity anomaly than in the gradient or differential curvature anomalies. The difference is much clearer if the vertical thickness of the body is very much less than the width. The difference between the anomalies of the subtypes of *A*, or of *B*, is recognizable, if the depth to the bodies is slight, or if the angle of slope of the inclined face is low and the depth to the bodies is moderate or slight. Asymmetry of the body is indicated by asymmetry of the anomaly, but the latter is necessarily the smaller. On the other hand, the area of the anomaly is greater than the area of the body to which it is due.

Isogams (the lines of equal intensity of gravity) have a seductive resemblance to structure contours. But, in general, isogams are convertible only indirectly into such contours. The relative gravity anomalies (Fig. 13) of the similar classes of bodies of Fig. 12 show the impossibility of simple conversion, and indeed the relation is indirect and complex. The three types of class *B*, Fig. 12, geologically represent a block fault, a broad anticline, and a broad syncline respectively; yet the difference between the general form of their respective anomalies is slight unless the bodies are close to the surface; and the anomaly may be either a maximum or a minimum depending on the relative density of the body. Simple transformation of the isogams of an asymmetric anomaly into structure contours, therefore, can lead to serious error in visualization of the structure. Approximate conversion of isogams into structure contours, however, is possible if the slope of the surface of the causative mass is only a few degrees, and if its width is large in reference to its depth.

Recognition of the presence of anomalous density is not possible under all conditions. These three quantities—relative gravity, the gradient, and differential curvature are not affected by—

(1) Infinite, plane, horizontal plates.
(2) Gently inclined plane plates, of great downward extension, in the zone where the thickness of the plate is less than 10 times its depth.
(3) Curved or warped plate-like bodies, approximately horizontal and of great extent, with the upper and lower surfaces parallel, except in areas where the depth to the top of the body is less than 3 times its thickness.
(4) Step-like bodies of type A, Fig. 12.
(5) Finite bodies of types B, C, D, Fig. 12, provided the depth of the body is greater than 10 times its thickness.

In the case of (4) and (5) observable anomalies would not be produced at half the depth-thickness ratios quoted if the relative density is small. For high relative density these ratios must be increased. Relative densities of 0·2–0·5 are regarded as normal; less than 0·1, very small; and more than 0·7, large.

Resolution of observed composite anomalies approximately into the constituent anomalies is an unfortunate necessity in all interpretation.

The form of an anomaly in which the geophysicist is interested is warped, distorted, and shifted by the interference effects of other anomalies; and satisfactory mathematical interpretation of the anomaly is possible only after the anomaly has been disentangled from the rest.

The anomalies of the surface irregularities and of the surface features commonly are smoothed out either by simple inspection and redrawing of the isogams or by several methods of 'averaging' of gradient, differential curvature, or relative gravity values at adjacent stations. 'Averaged' gravity pictures, however, should be used with care, and in general only in conjunction with the unsmoothed or unaveraged picture.

Resolution of a complex set of structural anomalies and a regional anomaly in general is impossible, for usually it is impossible to determine what the regional should be.

Resolution of a complex set of interfering salt-dome minima and a regional anomaly in the Gulf Coast in some cases is possible by elimination of the salt-dome minima. The latter have a small range of form and amplitude. By trial and error, various combinations of plausible salt-dome minima with their respective centres in various positions can be subtracted from the observed picture. There remains an approximation to the regional anomaly plus extraneous anomalies. The combination of least numerous positions of the minima is assumed to give the most probable distribution.

Quantitative calculation of the masses which approximately produce the observed anomaly are of high value, but are extremely tedious and are rarely made. From his general knowledge the geophysicist sketches a trial form of the bodies which presumably are producing the observed anomaly, assigns plausible relative densities, calculates the corresponding gradient, gravity, or differential curvature anomaly which would be produced, compares it with the observed anomaly, modifies his assumptions in regard to form and density of the masses, and by such trial and error calculations he finds the bodies whose calculated anomaly most closely fits the observations. The results of such calculations are qualitative to semi-quantitative rather than strictly quantitative. Calculations of the size, depth, and limit of the cap of Gulf Coast salt-domes for sulphur companies have been proved to have a high commercial accuracy, but in general the calculations give only certain limits to a series of mathematically possible structural situations, which would produce the observed effects. The limits in some cases may be close together, and in other cases far apart. But careful calculations always force the geophysicist to a sharper, more exact interpretation than that which he would be able to give from simple inspection or analysis of the data.

Quantitative calculation is not used as much in interpretation as it should be. The reasons are complex: the calculations are tedious; in oil work the exigences of the limitation of exploratory options or of competition in leasing will not wait on calculations which take many weeks; many geophysicists are not familiar with such calculations; and there is the psychological fact that in general in geophysics it is easier to get authorization for field men and equipment to acquire raw geophysical data than for office personnel to interpret the data. Quantitative calculations should become progressively more important in the interpretation of the future.

GEOLOGY OF GRAVITATIONAL PETROLEUM PROSPECTING

Geological Basis

The geological basis for the use of gravimetric surveys in prospecting for petroleum lies in the following relations between the accumulation of petroleum, structure, and the distribution of specific gravity in the subsurface:

(1) Specific gravity tends to be uniform horizontally, but to vary vertically in areas of horizontal, undeformed beds.

(2) Commercial accumulations of petroleum are generally found on geological structures, where there is deformation of the horizontally uniform distribution of specific gravity.

(3) Distributions of density, comparable in a complex way to the simple geometric bodies of Fig. 12, are produced by the formation of anticlines, synclines, upthrust or down-dropped fault blocks, grabens, and horsts, which affect the accumulation of petroleum.

A. Specific Gravity.

The specific gravity of common rock masses ranges from 1·0 to more than 3·0:

	Specific gravity
Diatomaceous shale, San Joaquin Valley, California	1·0
Soil and alluvium	1·5–2·0
Beaumont formation, Pleistocene sands and clays, Texas Louisiana Coast	1·8–2·1
Tertiary sands and clays, (*a*) at shallow depth	2·0–2·2
(*b*) at 7,000 ft. Gulf Coast of Texas and Louisiana	2·50 ± 0·03
Rock-salt	2·19 ± 0·03
Sandstones	2·2–2·6
Acid (massive) lava	2·4–2·6
Limestone	2·3–2·7
Granite, and other 'acid' rocks	2·6–2·9
Gneisses and schists	2·6–3·0
Anhydrite	2·8
Gabbro, basalt and other 'basic' rocks	2·7–3·0
Peridotites and allied rocks	3·0–3·3
Ferruginous rocks such as those of Lake Superior iron ore series and magnetic ore deposits such as those of the iron deposits of northern Sweden, and those of the sulphide Sudbury district in Ontario	3·0–5·0

Variation of Specific Gravity with Depth. Increase of specific gravity with increasing depth is the law of variation in a majority of petroleum areas (0·07 per thousand feet in the Gulf Coast down to a depth of 8,000 ft.). Sedimentary rocks other than anhydrite or massive limestone are lighter than the rock of the underlying crystalline basement. Thick stratigraphic sections of petroliferous sands, clays, and marls are lighter than underlying massive limestone or anhydrite series. Palaeozoic beds tend to be more consolidated, better cemented, and, therefore, heavier than post-Palaeozoic beds of similar lithologic character. Mesozoic beds, similarly, tend to be heavier than the comparable Tertiary beds. The specific gravity further tends to increase downwards in a thick section of sands, clays, and marls, for the older beds have been under more weight for a longer time and, therefore, are more compacted than the shallower, younger beds.

Decrease of specific gravity with depth is found, however, (1) if a massive salt series is present at considerable depth, (2) if a large thickness of diatomaceous shale is present at considerable depth, and (3) if a thick section of limestone, or if anhydrite, overlies a thick section of sands, shales, clays, marls, or other poorly consolidated beds.

Anticlines, the upthrown fault-blocks, horsts, buried 'granite' ridges, and all positive structures tend, therefore, to produce gravity maxima; and conversely, maxima in most cases tend to indicate the presence of positive structures.

Synclines, the down-thrown fault-blocks, graben, and all negative structures tend, therefore, to produce minima. Nevertheless salt-domes, ridges, the Lost Hills anticline (whose core is composed of diatomaceous shale) produce minima. And the synclinal thickening of the Hunton limestone at Seminole in Oklahoma produces a synclinal maximum.

Salt-domes. A salt-dome presents a large, clearly defined, sharp anomaly of specific gravity. A salt-dome in the Gulf Coast consists of the frustum of a cone of salt capped by a cylinder or thimble-like mass of limerock-anhydrite-gypsum and is intruded into 20,000 to 30,000 ft. of Tertiary and Cretaceous sands and clays. The diameter of the top of the salt core mostly is between 1 and 3 miles; the height of the salt core above its base is 3 to 6 miles; and the difference between the specific gravities of the salt and the surrounding beds ranges from 0 to +0·20 at the surface to −0·5 (estimated) at 20,000 ft. below the surface. The cap has a vertical thickness of 200 to 500 ft., but on a few domes of 900 to 1,000 ft. The difference between the respective specific gravities of the cap and the surrounding sediments is +0·5 to +0·7.

A characteristic shallow salt-dome in the Gulf Coast produces a composite anomaly which consists of a small maximum within a large minimum. The 'small' and 'large' refer simultaneously to area and to amplitude.

The cap, having a large positive relative density, produces a gravity maximum (Fig. 14). The cap lies relatively close to the surface; the maximum has a large value relative to that of extraneous regional variations of gravity and is not appreciably shifted by them; the maximum, therefore, lies directly above the top of the dome and is only slightly wider than the cap. The upper part of salt in domes close to the coast in Texas and Louisiana has a slight positive relative specific gravity in comparison to the surrounding Pleistocene and Recent sands and clays, and helps the cap in producing a gravity maximum. The diameters of the shallow dome maxima are approximately 1½ miles for average-sized domes, but range up to 4 miles for the larger domes. The amplitude of these maxima is of the general order of 0·6 milligal.

The lower half of the salt core of a shallow dome, on account of its negative relative specific gravity, produces a gravity minimum (South Liberty minimum, north-east corner of Fig. 15. As the depth to which the salt extends is great, the width of the minimum is correspondingly large and ranges from 8 to 15 miles. The amplitude of the minimum varies with the diameter of the salt core and with the downward flare of the flanks. The amplitude in the Gulf Coast is about 2·5 to 3·5 milligal, but may reach 7·0 milligal. Some shallow domes have no recognizable minimum, but calculations show that a cylindrical salt core slightly less than 1 mile in diameter may have a minimum of only 1·0 milligal; and an anomaly of 8 miles in diameter and of 1 milligal in amplitude is not recognizable in practice on account of the obscuring effects of the extraneous anomalies. The gradient on these salt-dome minima has the same general magnitude as the gradient of regional features, or of the resultant gradients of minima of adjacent domes. The centre of the minimum, therefore, may be shifted considerably by the combined effects of the other anomalies. The upper half of the salt core of salt-domes well back from the coast has a negative relative specific gravity, and, therefore, aids in producing the

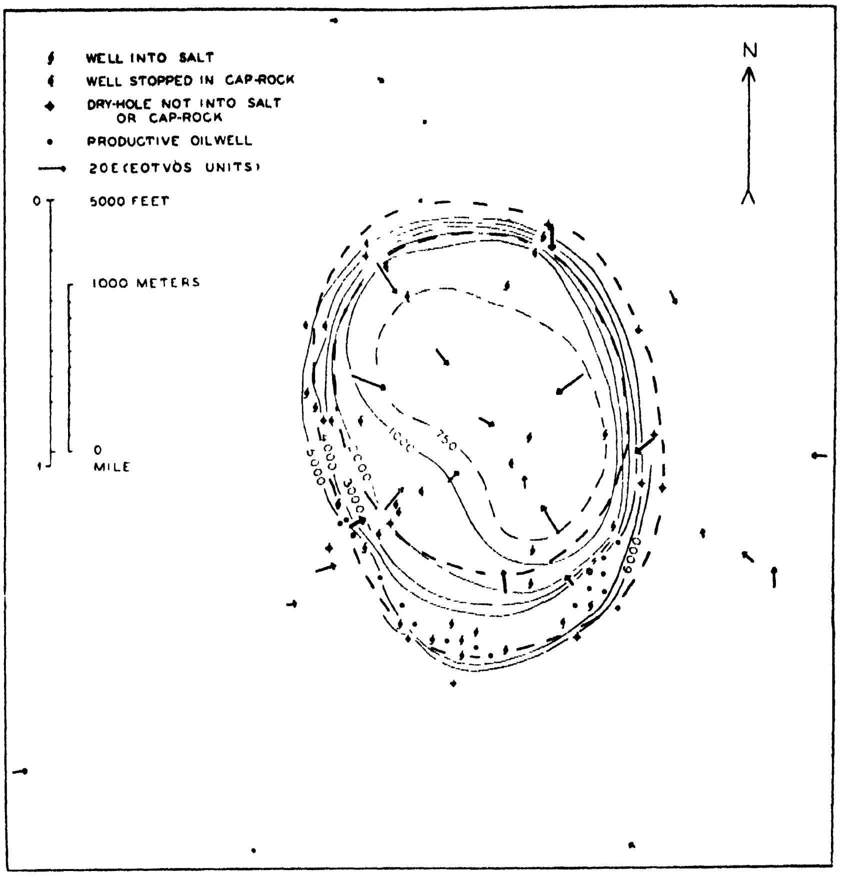


FIG. 14. GRAVITY MAXIMUM OF A SHALLOW SALT-DOME in the Gulf Coast, Nash Salt Dome, Brazoria, and Fort Bend Counties, Texas (after Barton, in *Geophysical Prospecting 1929*, A.I.M.E.).

Gradient arrows are superimposed on the structural contours on the top of the cap-salt.

Nash was the first salt-dome to be discovered by geophysics in the Gulf Coast. It was discovered on the basis of these gradient arrows. The two heavy dashed lines were the 500–900-ft. and 4,000–5,000-ft. contours on the cap-salt which were predicted by the writer in advance of drilling. The convergent gradient arrows well away from the dome are presumably more the effect of large minima to the west, north, and east than of the Nash Dome.

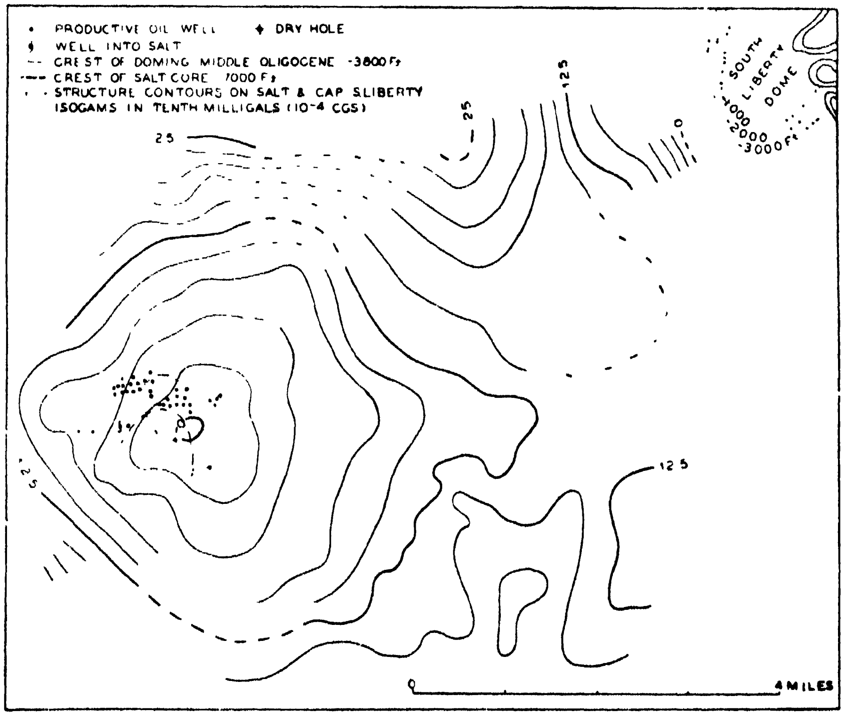


FIG. 15. ISOGAMS OF SALT-DOME MINIMA. (After Barton, in Bulletin, American Association Petroleum Geologists.)

This map shows the isogams due to:

(*a*) the minimum of a deep salt-dome, Esperson, the top of whose salt core lies at a depth of 7,000 ft.;

(*b*) part of the minimum around a shallow dome, South Liberty, Texas, the top of whose cap rises within 320 ft. of the surface; and

(*c*) the maximum ridge between the two minima.

The shift of centre of the minimum eastward from the crest of the dome is surmised to be due to asymmetry of the salt mass. Quantitative calculations suggest that the west flank of the dome is steeper than the east flank; the centre of the anomaly, therefore, should be slightly down the east flank.

The Esperson dome was discovered on the basis of this survey. These isogams are by the author. The original survey and interpretation were by Christian Iden, Union Exploration Company.

minimum. Most shallow domes show both the maximum and the minimum, but on some domes the one or the other is too faint to be observed.

A deep salt-dome is much the same gravitationally as the lower half of a shallow dome and, therefore, produces a similar minimum (Fig. 15). Even if a thick cap is present, the ratio of its thickness and volume to its depth would be so small that its effect on gravity at the surface would not be observable.

The anomalies of shallow salt-domes in east Texas and in north Germany do not show any maximum immediately above the dome, but are exclusively minima. The salt cores of those domes rise through a thick section of Cretaceous beds, which include much limestone, and through only a thin overlying section of Early Tertiary beds; the uppermost part of the salt core has, therefore, a negative relative specific gravity, while that of the salt as a whole is much larger than for the Gulf Coast domes, which also have the thicker caps. The amplitude of the minimum, therefore, is much greater than that which an identically similar dome in the Gulf Coast would have; the amplitude of the maximum effect of the cap-rock is smaller; and the minimum totally obscures that faint effect. But, on the other hand, the doming of the limestone produces a maximum effect which tends to counteract the minimum of the salt.

The greatest success in the use of the gravitational methods of prospecting for petroleum has been in connexion with salt-domes.

B. Regional Framework of an Area.

Regional gravity surveys give a valuable, although not complete, picture of the geology and structure of an area.

The regional gravity anomalies predominantly are the effect of major warping of the basement. The effective difference in specific gravity lies between the thick sedimentary cover of sands, weak sandstones, clays, shales, marls, salt, and subordinate limestone and anhydrite, and the underlying basement. The latter may be either the crystalline basement of igneous and metamorphic rocks or a series of limestones, well-consolidated sandstones, or highly compacted shales, which lie on the crystalline basement.

But such anomalies may also be produced either by heavy batholithic masses within the basement, or by lateral changes in a thick prism of sediments. An example of the former is given presumably by the Crosbyton maximum, Crosby and Garza Counties, (west) Texas. The circular anomaly has a width of 50 miles. The gravity anomaly has an amplitude of 70 milligal, and the magnetic anomaly of Z has an amplitude of 2,500 gammas. The vertical dimension of the extra heavy mass is 4 miles or more, according to some calculations by the writer. Normal beds at usual depths were found by a well which was drilled to a depth of 5,000 ft. on the crest of the anomaly. According to the writer's present interpretation, this anomaly must be produced by an ultra-basic, perhaps peridotitic igneous mass within the basement.

Examples of the effect of large lateral lithologic changes are given by the great limestone reef of the south-west central Permian basin of west Texas and south-eastern New Mexico. The changes are from relatively light beds to massive limestone through a vertical stratigraphic section many thousand feet thick. A large gravity maximum comparable to that of a buried mountain range is thereby produced.

The regional framework of central southern Oklahoma and adjacent Texas is depicted in good agreement with and beyond the geologic data by the regional gravity map of Fig. 16. The Wichita Mountains, the Arbuckle Mountains, and the Nocona-Muenster buried mountain ridge, like such structural masses in general, are represented by maxima, and the intervening deep sedimentary basin is seen as a broad minimum. The Nocona-Muenster ridge is shown to be the south-eastern continuation of the Wichita Mountain

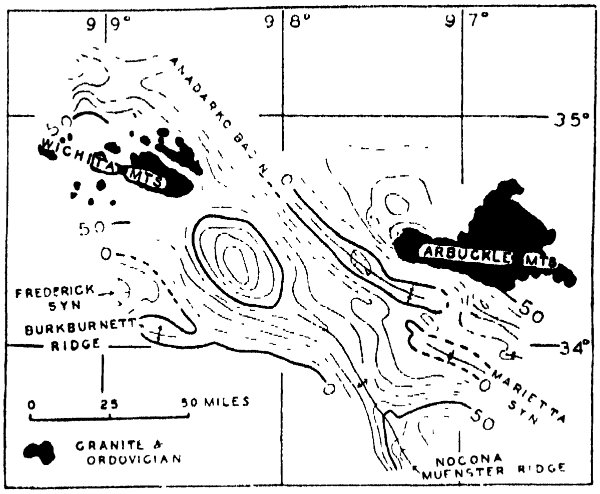


FIG. 16. REGIONAL SURVEY. Isogam map of Central Southern Oklahoma and adjacent Texas (mostly after Van Weelden, *Proc. Intern. Petroleum Congress*, London, 1933).

system, although geological confirmation of the connexion is not yet available. The Criner Hills, a sharp local uplift, which brings Ordovician to the surface through the Pennsylvanian and Permian beds, produces the maximum which lies between the *échelon* overlap of the Marietta and the Anadarko(-Ardmore) minima. Healdton and Hewitt, sharp structures which bring Ordovician limestone within reach of the drill in those oilfields, produce the nose of maximum between the Anadarko minimum and the vague north-west extension of the Marietta minimum. The Burkburnett buried 'granite' (crystalline) ridge and the Frederick syncline to the north-west are represented respectively by a maximum and a minimum.

C. Anticlinal Maxima and Elimination of Regional Effects.

Anticlines frequently produce maxima, and a corresponding anomaly in the differential curvature, provided the specific gravity of the beds increases downwards.

Anomalies of such type are shown by the Fort Collins anticline in Colorado (Fig. 17). That structure is a sharp fold in a thick section of Cretaceous shales and weak sandstones. The structure contours of Fig. 17 were mapped at the surface, on the Hygiene sandstone member of the Pierre shale (Upper Cretaceous) as the datum horizon.

The gradient arrows sharply define a maximum coincident with the anticline.

The differential curvature anomaly of the anticline is masked by a regional anomaly and can be recognized only after elimination of the regional effect. A crude study of such elimination is made in Fig. 17*B*. The profiles of U_{Δ} and U_{xy} are plotted for a transverse line across the anticline. The dashed diagonal line in each graph represents the assumed variation of the regional effect. The deviation of

each observed value from the corresponding value of the dashed line is assumed to be the effect of the local structure. The data are not extensive enough for a reliable study of the elimination of a regional anomaly, but the resulting residual values of the differential curvature which are plotted in Fig. 17*C* are essentially those which the structure at the Fort Collins anticline should produce. The differential curvature lines over the crest of the anticline should be at a maximum, and should be parallel to the longitudinal axis of the anticline; and a synclinal trough, such as that between the west flank of the anticline and the regional eastward dip, should produce differential curvature lines at right angles to the longitudinal axis of the trough.

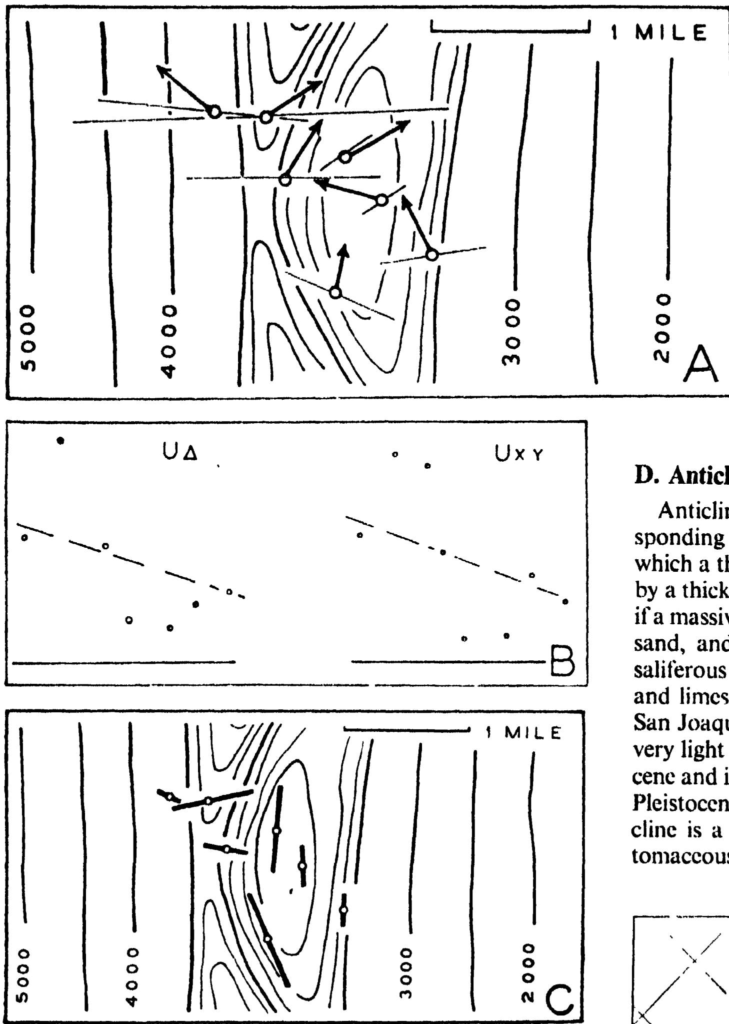


FIG. 17. AN ANTICLINAL MAXIMUM. Fort Collins anticline, Larimer County, Colorado (*A* after J. H. Wilson, *Colorado School of Mines Magazine*, **17**, Oct. 1928).

A. Gradient arrows and differential curvature lines superimposed on structure contours (after U.S. Geological Survey) on Hygiene sandstone of Pierre Shale (Upper Cretaceous).

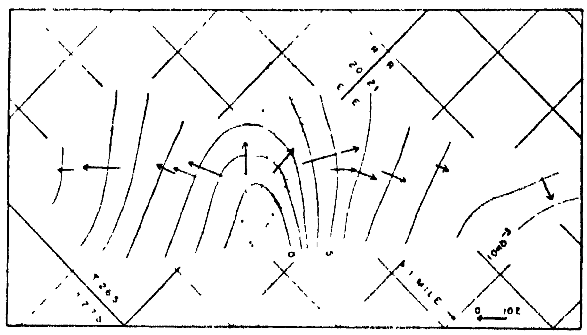
B. A study of the elimination of the regional anomaly in the differential curvature.

C. Residual differential curvature lines (from the analysis in *B*) superimposed on the structure contour map.

D. Anticlinal Minima.

Anticlines will produce gravity minima, and the corresponding type of differential curvature anomaly, in areas in which a thick section of relatively heavy beds is underlain by a thick section of lighter beds. Such a situation obtains: if a massive limestone section overlies a thick section of clay, sand, and weak sandstone; if a thick section of salt, or saliferous beds, underlie a section of sand, clay, sandstone, and limestone. In the south-western part (Fig. 18) of the San Joaquin Valley of California, 3,000 ft. more or less of very light diatomaceous shale is present in the Upper Miocene and is overlain by many thousand feet of Pliocene and Pleistocene sands, clays, and gravels. The Lost Hills anticline is a very sharp, possibly diapiric, fold of that diatomaceous shale up to shallow depth below the surface.

A



B

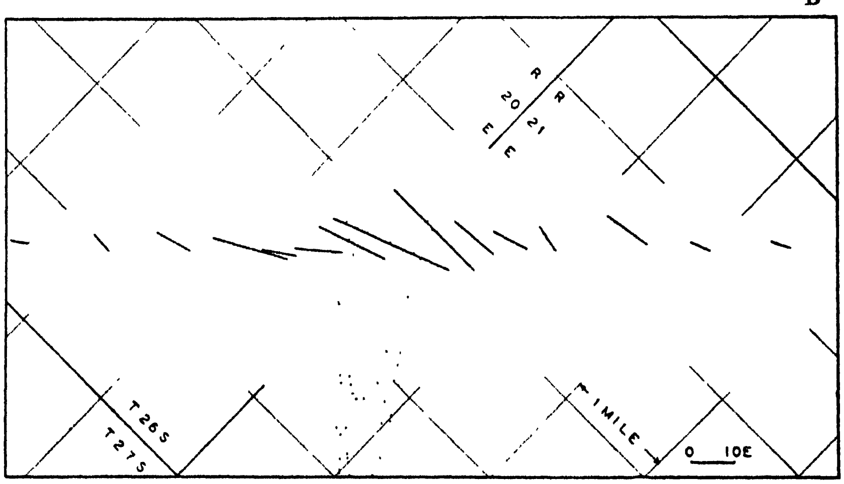


FIG. 18. ANTICLINAL MINIMUM. Lost Hills anticline, San Joaquin Valley, California (survey by, and released through the courtesy of, Paul E. Getty, Inc.).

A. Gradient arrow-isogam map; structure contours drawn on shallow oil sand; isogam interval 1 milligal.; structure-contour interval, 100 ft.

B. Differential curvature lines superimposed on the same structure contours.

The gravity anomaly of the Lost Hills anticline, therefore, is a minimum, and the differential curvature is perpendicular to the longitudinal axis of the anticline instead of parallel as in the case of the anticlinal maximum. The sharpness of the gradient, gravity, and differential curvature anomalies over the crest of the anticline show that the anomaly is anticlinal and not synclinal, even if the drilling data were not available.

E. 'Buried' Ridges.

'Buried' ridges such as the Muenster 'granite' ridge of northern Texas produce maxima (Figs. 16 and 19). The Muenster ridge consists of a core of granite, gneiss, schist, and Ellenburger (Ordovician) limestone rising into a cover of Carboniferous and Cretaceous shales, sandstones, and limestones. The anomaly in large part is the effect of the contrast in specific gravity between the core of basement rocks and the overlying relatively less dense beds. If the burying beds are predominantly limestone, the difference in specific gravity between the rocks of the cover and those of the core of the ridge may be too small to produce an observable anomaly.

F. Faults.

Faults produce observable anomalies, but these are often narrow and faint and may be difficult to distinguish from the anomalies of surficial irregularities.

An observable anomaly will be produced by the part of the fault which lies very close to the surface, and the anomaly will be very narrow.

In order to map narrow anomalies, the interval between stations on a profile must be 50, 100, 150 ft., and adjacent profiles should not be many hundreds of feet apart. Such mapping in petroleum geophysics is unprofitable except under exceptional circumstances.

The mapping of faults is, however, sometimes practicable.

The Luling fault is of such a type. The anomaly (Fig. 20) is produced by the large contrast in specific gravity between the abutting masses of the upthrown block of Edwards limestone (Georgetown and Buda limestones, not differentiated in Fig. 20) and the downthrown block of Taylor marls and clays (Del Rio clay not shown in Fig. 20) and Austin chalk. These abutting, contrasting masses lie at a depth of 2,000 ft. The difference of specific gravity across the fault above and below that zone is very small. An observable anomaly, approximately 4,000 ft. wide, therefore, is produced by that one zone of contrasting density and lies immediately above the trace of the fault in that zone. A second narrow observable gradient and gravity anomaly should be produced along the surface trace of the fault. But the net of stations on this survey was not sufficient to map this. The differential curvature rather commonly, as in Fig. 20, shows greater effect from the shallower part of the fault.

RETROSPECT

A. Geological Interpretation versus Geological Probability

Interpretation of the geophysical data in general should be guided by the known geology and geological probabilities of the particular area.

The exceptional case not uncommonly arises, however, in which a geophysical survey indicates the presence of some radically unorthodox geological feature which is contrary to well-accepted concepts of the geology and geological probabilities of the area. The south-eastward regional gradient of the survey across the Luling fault presents such an exceptional case (Fig. 20).

The Luling Field lies south-east of the Llano-Burnett uplift of pre-Cambrian granites and metamorphics. The dip of the beds at the surface, east to south of the uplift, is eastward into the east Texas geosyncline and south-eastward to southward into the Gulf of Mexico, past the area of the Luling Field. According to former surmise, the surface of the pre-Cambrian rock dipped in the same way. The regional gravity gradient, therefore, should have been towards the Llano-Burnett uplift up the slope of that basement surface.

The reverse regional gradient, south-westward down that supposed slope of the basement surface, is present in the Luling area. Its significance was not understood at the time of this survey (1925). The physical-mathematical significance was clear, but all of the geophysically plausible interpretations seemed contrary to fairly well-established geology.

A Palaeozoic trough, perhaps comparable to the Appalachian trough, was shown by subsequent deep drilling into the Palaeozoics to lie between the Luling area and the Llano-Burnett uplift. The gravity surveys in the Luling area were mapping the east side of that trough. But at the time of the surveys the geologist would have regarded the interpretation by the geophysicist of the presence of such a trough as geologically improbable. The gravity surveys which were available to the author at the time were inadequate for interpretation of the regional anomaly, but were adequate to indicate the presence of some feature contrary to the accepted geological picture of the subsurface.

The geophysicist in general must be extremely cautious in making interpretations contrary to well-accepted geological concepts of what is possible or probable. But the geologist frequently has formed his concepts of the subsurface from inadequate and partially inaccurate data, and individual geologists may form concepts by erroneous reasoning. The geophysicist, therefore, should not hesitate cautiously to make geologically unorthodox interpretations, if careful reconsideration of his geophysical data force him to them, and if re-examination of the geological data and reasoning does not definitely preclude his interpretation.

B. Limitations of the Gravitational Methods

The gravitational method is useless unless effective variation of specific gravity with depth is present. A 'buried' granite ridge mantled with limestone cannot be detected, unless the upper surface of the limestone series is warped over the 'ridge'. Fair-sized structures in a thick series of relatively homogeneous beds may not produce observable or definite anomalies, particularly if the basement is deep and is not considerably deformed. A great many productive structures do not produce observable gravitational anomalies. A synclinal maximum may be indistinguishable from an anticlinal maximum. An observed salt-dome minimum may not indicate whether the salt or the super-salt doming of the sediments comes within reach of the drill. A batholithic mass within the basement may not be distinguishable from deformation of the surface of the basement. The effects of sharp lateral changes may obscure or mask the structural anomalies. The interference of the anomalies from the deep basement with those of shallower

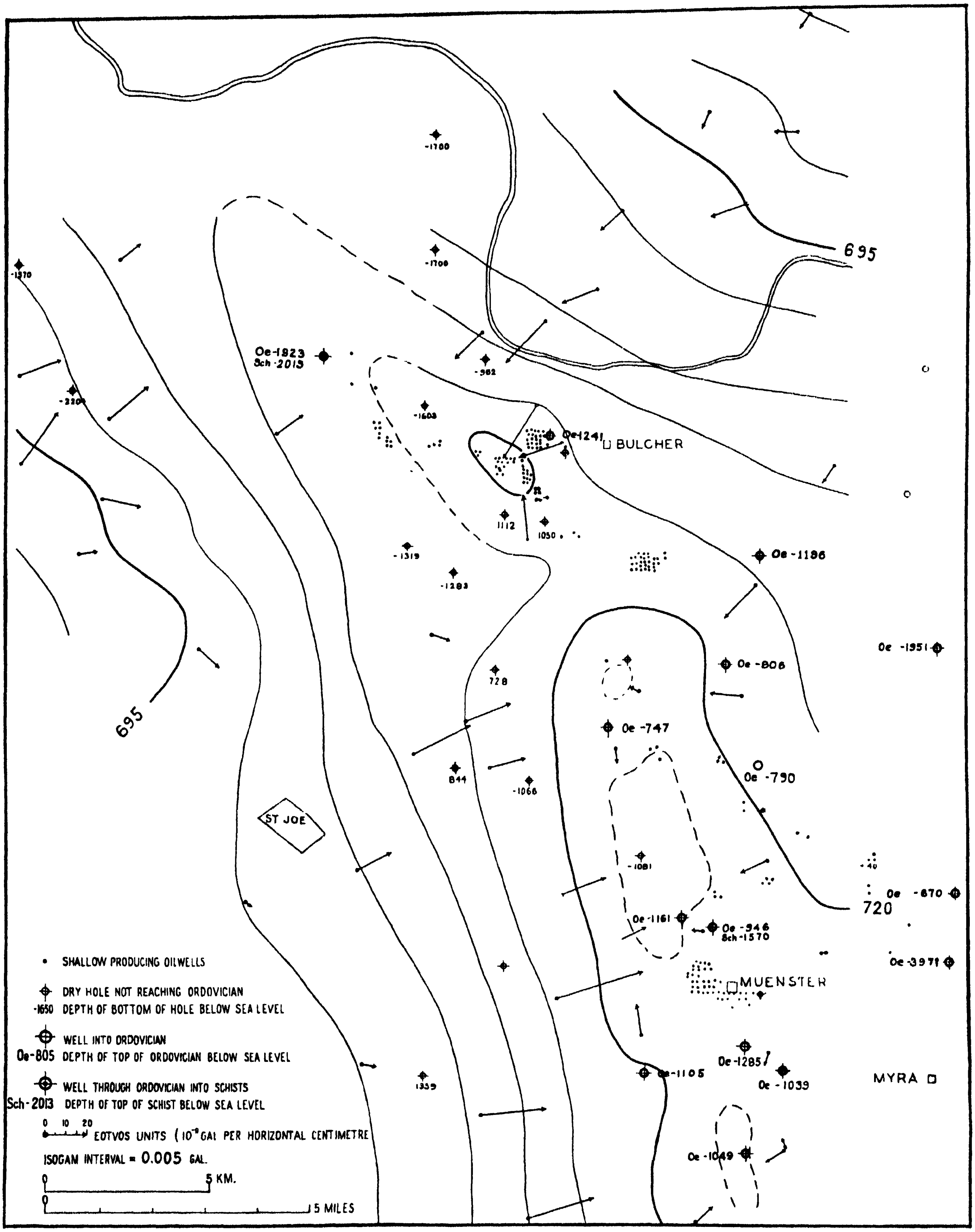


FIG. 19. 'BURIED' CRYSTALLINE-LIMESTONE RIDGE. Isogam-gradient arrow map of the Muenster 'Granite' Ridge, Cooke and Montague Counties, Texas (after Barton, *Geophysical Prospecting 1929*, American Institute of Mining and Metallurgical Engineers). This map covers a small part of the area of the map of Fig. 16.

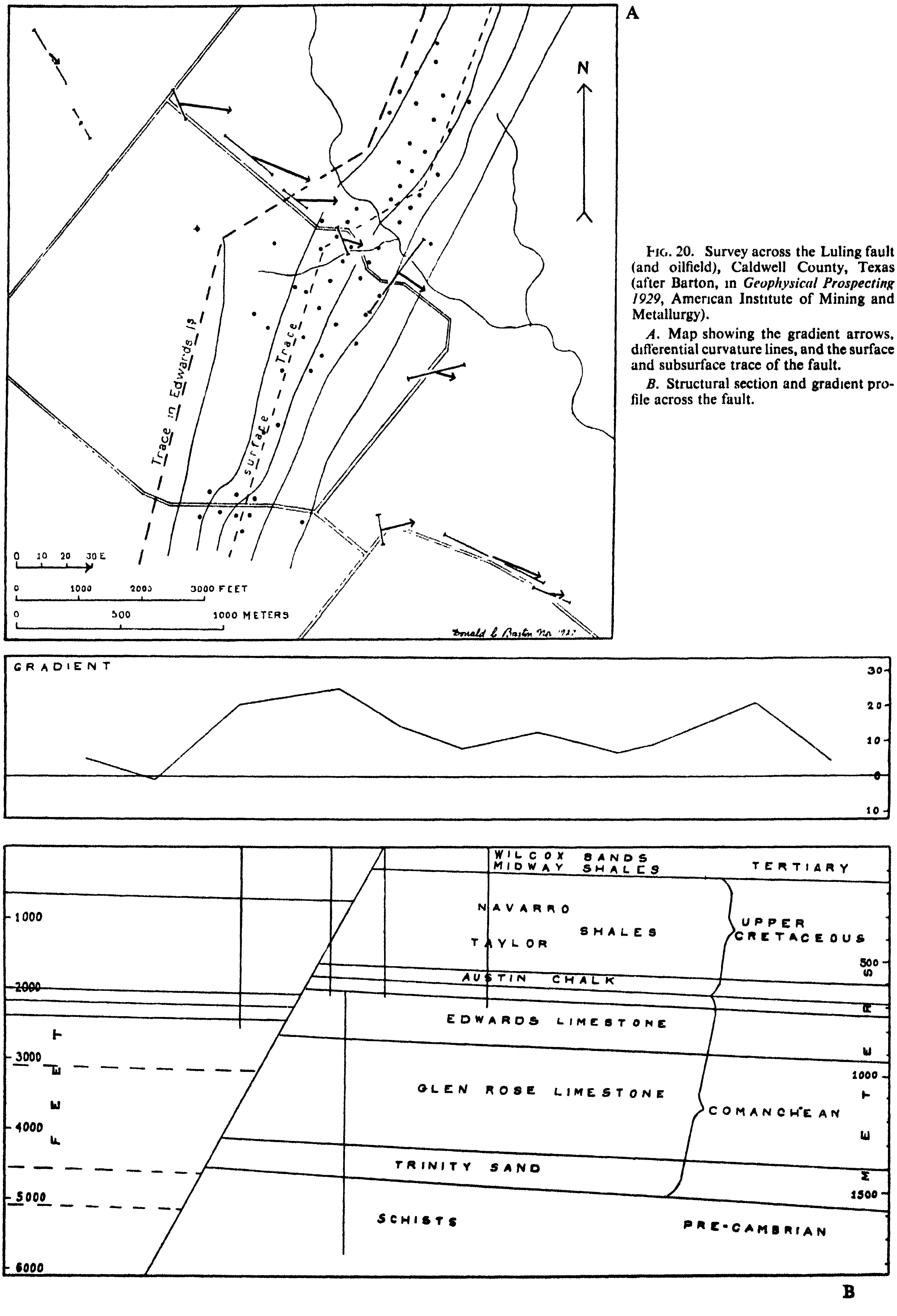


FIG. 20. Survey across the Luling fault (and oilfield), Caldwell County, Texas (after Barton, in *Geophysical Prospecting 1929*, American Institute of Mining and Metallurgy).

A. Map showing the gradient arrows, differential curvature lines, and the surface and subsurface trace of the fault.

B. Structural section and gradient profile across the fault.

structures, and the interference between anomalies of adjacent vertically elongated structures, may produce a complicated gravity picture and the analysis in such cases is never wholly satisfactory.

Surveys over a large area are necessary for proper interpretation of most local structural anomalies. If a good geologist were placed in an area about whose geology he knew nothing, if he could get no information from the literature or from other geologists, and if he were confined within the area of a local structure, he would hesitate about making much interpretation of the structure and its oil potentialities. The geophysicist is subject to a parallel but more rigid limitation.

Surveys with the torsion balance are slow. Unless an army of torsion balances is thrown into an area, quick completion of the survey of a considerable area is impossible.

The effective use of the torsion-balance in surveys is severely limited by the terrain. Rugged topography prevents such surveys, except under exceptional circumstances. Observations with the torsion balance are impossible over deep water, and are taken with difficulty in open shallow water. Heterogeneous alluvial deposits, irregular weathering of bed-rock, small-scale irregularities of the surface of the bed-rock buried under slight or moderate cover of soil or alluvium, irregular alluvial cut and fill, some glacial deposits, produce much irregularity in the gradient and differential curvature, which can be overcome, if at all, only by multiplication of stations.

Differential curvature cannot be determined by pendulum or gravimeter and this is a serious objection to the use of these instruments on a survey. Many are not competent to handle the interpretation of the differential curvature; it is more sensitive to irregularities of topography, and correction for such effects is not as successful as the gradient. The differential curvature, therefore, is neglected by many geophysicists. It is of very great value in the interpretation of many surveys, and in some it may be of more use than the gradient.

The scarcity of really first-class interpreters is a serious limitation to the use of the methods. Interpretation is not so simple as it is believed to be by most physicists and geologists. The technique of interpretation has a very considerable content, only a little of which is known to most of the men who are actually engaged in such work. A thorough training in the mathematics and technique of interpretation, with wide practical experience of gravitational surveys which have been checked against known geology, besides sound training and experience in geology are all necessary for really first-class interpretation, but unfortunately are possessed by few men.

Nevertheless, gravitational methods in petroleum geophysics have not been precluded by all these limitations. Good commercial success has been obtained with the gravitational methods in prospecting for petroleum. In the Gulf Coast of Texas and Louisiana the largest geophysically discovered oilfield, Thompson (Rabbs Ridge), Fort Bend County, Texas; two of the next largest geophysically discovered oilfields, Sugarland and Tomball, Fort Bend and Harris Counties respectively, in Texas; several large oilfields: Manvel, Brazoria County, Texas; Dickinson, Galveston County, Texas; Roanoke, Jefferson Davis Parish, Louisiana; several less good oil-fields: Esperson, Liberty County, Texas; Hankamer, Chambers County, Texas; and the smaller oilfields: Nash, Fort Bend and Brazoria Counties, Texas; Cleveland, Liberty County, Texas; and Mykawa, Harris County, Texas, were discovered by gravitational surveys and, with the exception of Cleveland, torsion-balance surveys. The ratio of barrels of oil discovered, to dollars spent is surmised to be greater for the torsion balance than for the seismic method. The torsion balance was of good use in the early days of the Hendricks field, Winkler County, Texas, in the future extension of the field. The torsion balance aided the magnetometer in the discovery of the very large Hobbs oilfield, Lea County, New Mexico.

In spite of their serious limitations, the gravitational methods have won a permanent place in petroleum geophysics.

NOTES

[1] A galileo is a unit of acceleration, that is, one centimetre per second per second. Hence the gal.

[2] Also Horizontal Directive Tendency (H.D.T.), and sometimes 'R' lines or values, from Baron Eötvös's term *Richtkraft*.

[3] Several steps are necessarily omitted; MW and NW are directed lengths depending on the dimensions and orientation of the balance. The theory is given in full in *Applied Geophysics* by Eve and Keys (Camb. Univ. Press), pp. 185–203; 2nd edition, 1933.

[4] In the mathematical theory U denotes the *gravitational potential* whose space rate of change in any direction gives the component of the force on unit mass in that direction.

[5] The 'probable error' by definition is the error such that errors numerically larger or smaller are equally probable.

[6] A dyne force acting on a gram mass produces an acceleration of 1 cm./sec.^{2}, here called a gal. One thousandth of this has been termed by some a gamma. Horizontal lines of equal vertical intensity of gravitational attraction have been called *isogams*. This word may have originated with magnetic surveys.

THE REFRACTION METHOD OF SEISMIC PROSPECTING

By J. H. JONES, Ph.D., D.Sc.
Chief Geophysicist, Anglo-Iranian Oil Company

I. History of the Method

ABOUT the middle of the nineteenth century Robert Mallet made perhaps the first attempt to investigate the transit velocities in rocks of elastic waves due to artificial earthquakes.

In these experiments, carried out in Ireland and North Wales, Mallet determined the velocities of earthquake (or seismic) waves passing through various rocks. The values that he found ranged from 825 ft. per sec. through sandstone to 1,665 ft. per sec. for granite. These velocities are of course much lower than the compressional and distortional wave velocities in these rocks, and probably represent the velocities of surface waves. Later, velocity determinations were made by Pfaff in Germany (1873), by Abbot in America (1878), and by Milne in Japan (1888).

A paper on 'Wave Propagation and Earthquakes' by Schmidt appeared in 1888. In this paper Schmidt considered the possibility of the velocity of the wave increasing with depth, and suggested that the variation with depth might be obtained from time-distance graphs of artificial earthquakes.

Further determinations of velocities were made by Fouque and Levy in 1899, and by Hecker in 1897–1900. The latter investigator observed that the main wave was preceded by small disturbances which appeared to travel with higher velocity. He suggested that the small forerunning waves were of the compressional type and that they would not, in general, travel direct from the focus to the observation point, but would follow another path determined by the ratio of elasticity and density at different depths within the earth.

In 1901 an article suggesting a new practical application of seismometers was written by A. Belar. In this article Belar suggested that seismometers could be used to obtain useful information regarding subsurface conditions in connexion with the construction of tunnels along the Tauern Railroad.

During the close of the nineteenth, and the beginning of the twentieth, century the science of seismology was put on a quantitative basis by the classical researches of Milne and his collaborators in Japan, and of Wiechert and his pupils in Germany. Subsequent investigations have been based on the foundations laid by these seismologists. Wiechert, in particular, showed how the physical properties of the earth's crust could be studied with the aid of time-distance graphs of natural earthquakes. His investigations led him to believe that there were surfaces at which the velocity changed abruptly; these abrupt changes were indicated by singularities in the time curves, brought about by a sudden change in the slope.

A very definite suggestion appears to have been made by von dem Borne in 1908 for applying the principles established by Wiechert to the smaller-scale problem of investigating the geological structure of the outermost layers of the earth's crust. It was some years later, however, before the actual practical application to this important problem was made by Mintrop, who realized the possibilities of the method in economic geology. Mintrop applied for patents on his refraction method in Germany in 1919. The method was introduced into the United States late in 1923.

Some years before the development of the refraction method by Mintrop, the suggestion had been put forward by A. Mohorovičić that the initial disturbance recorded at stations close to the epicentre was caused by a wave which had travelled along an indirect path.

A mathematical treatment dealing with the formations of the indirect wave was made by Jeffreys in a paper to the Cambridge Philosophical Society in 1925. Jeffreys considered the problem of the compressional wave in two horizontal layers. His analysis shows that an explosion in the upper medium produces, in addition to the direct surface and reflected waves, an indirect wave which appears to have travelled along the interface with the velocity of sound in the lower medium. It is found that the variation of amplitude with distance from the focus is in reasonable accordance with seismological observations and that the time of travel is that along a path determined by the law of refraction. The theoretical aspects of the problem have also been considered by Morris Muskat in a paper 'The Theory of Refraction Shooting', *Physics*, **4**, Jan. 1933.

II. The Mintrop Method

The method invented by Mintrop to determine the depth of a covered horizontal layer is described in a patent application filed in December 1919 in Germany, and in the United States in December 1920 [6]. In this application Mintrop briefly considers the two-layer problem, and shows how the depth of the lower layer can be calculated from the time-distance curve.

A disturbance is set up in the ground by the explosion of a charge of dynamite at or near the surface, and the movement of the ground is recorded with portable seismographs at different points along a linear traverse. The time of the first pulse is determined at each observation point along the line, and a graph is constructed showing how the time varies with distance from the point of explosion. At the nearer points the first wave-pulse will have travelled along, or close to, the surface, and the slope of the first part of the time curve will be a measure of the velocity of the elastic wave in the upper medium. At greater distances the indirect wave-pulse will arrive first, and the slope of the time curve will now be a measure of the velocity of the elastic wave travelling in the lower medium. At some intermediate point the direct wave-pulse arrives simultaneously with the indirect one, and because the slopes are different on either side of this point there will be a discontinuity in the time curve.

The depth of the lower layer is calculated with the aid of a formula involving the distance of the point of discontinuity from the origin and the value of the slopes of the two branches of the time curve.

Fig. 1 shows the assumed path of the indirect wave. The ray *OA* falls on the surface *AB* at an angle θ with the normal. This angle is the critical angle of refraction and is given by the usual relation $\sin\theta = v_1/v_2$. The disturbance travels along the surface *AB* of the lower layer, and

secondary disturbances travel across the upper layer along paths BC, B_1C_1, &c., again making the same angle θ with the normal to AB. When OC is sufficiently large, the path $OABC$ becomes the shortest time path between O and C.

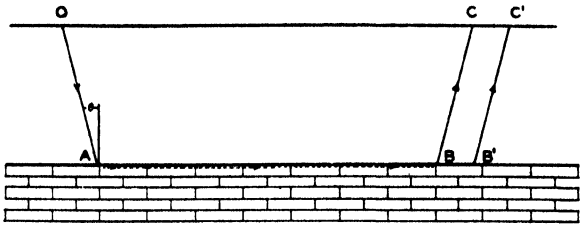


FIG. 1

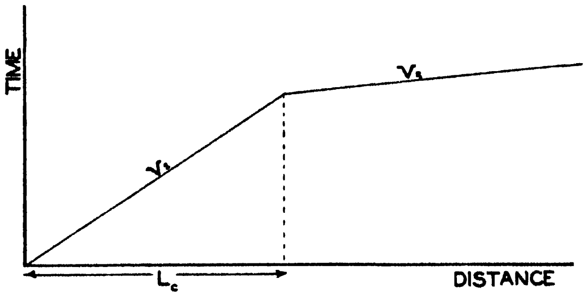


FIG. 2

Fig. 2 shows the type of linear traverse time curve. It can be shown that the depth H of the surface of the lower layer can be obtained from the two velocities v_1 and v_2 and the distance of the discontinuity (L_c), by the relation

$$H = \frac{L_c}{2}\sqrt{\left(\frac{v_2-v_1}{v_2+v_1}\right)} \tag{1}$$

(Equate L_c/v_1 and $2H/v_1 \cos\theta + (L_c - 2H\tan\theta)/v_2$. This means that the direct shock arrives at the same time as the long-path shock). Again, it is easy to show that the time along the indirect path at a point on the surface distant L from O is given by

$$t = \frac{L}{v_2} + \frac{2H\cot\theta}{v_2}. \tag{2}$$

The relation (2) is often used to determine the depth H.

Apparent Velocity.

The slope v_2 of the time curve in Fig. 2 will be a measure of the velocity of the elastic wave in the lower layer only when this layer is horizontal.

When the layer is inclined it is necessary to determine the slope of the time curve when the direction of travel is reversed; the arithmetic mean of the two slopes gives a close approximation to the true velocity when the angle of inclination is small.

Thus if the inclination of the layer to the horizontal is ϕ, v_2 is the true velocity in the layer, θ is the critical angle, the slope of the time curve when the wave is travelling up-dip is given by

$$v_2' = \frac{v_2\sin\theta}{\sin(\theta-\phi)}, \tag{3}$$

and down-dip by

$$v_2'' = \frac{v_2\sin\theta}{\sin(\theta+\phi)}. \tag{4}$$

The true velocity v_2 and the dip ϕ can be determined from these two equations when the angle θ is known.

For small values of ϕ,

$$v_2' = v_2(1+\phi\cot\theta),$$
$$v_2'' = v_2(1-\phi\cot\theta),$$

so that

$$v_2 = \frac{v_2'+v_2''}{2}. \tag{5}$$

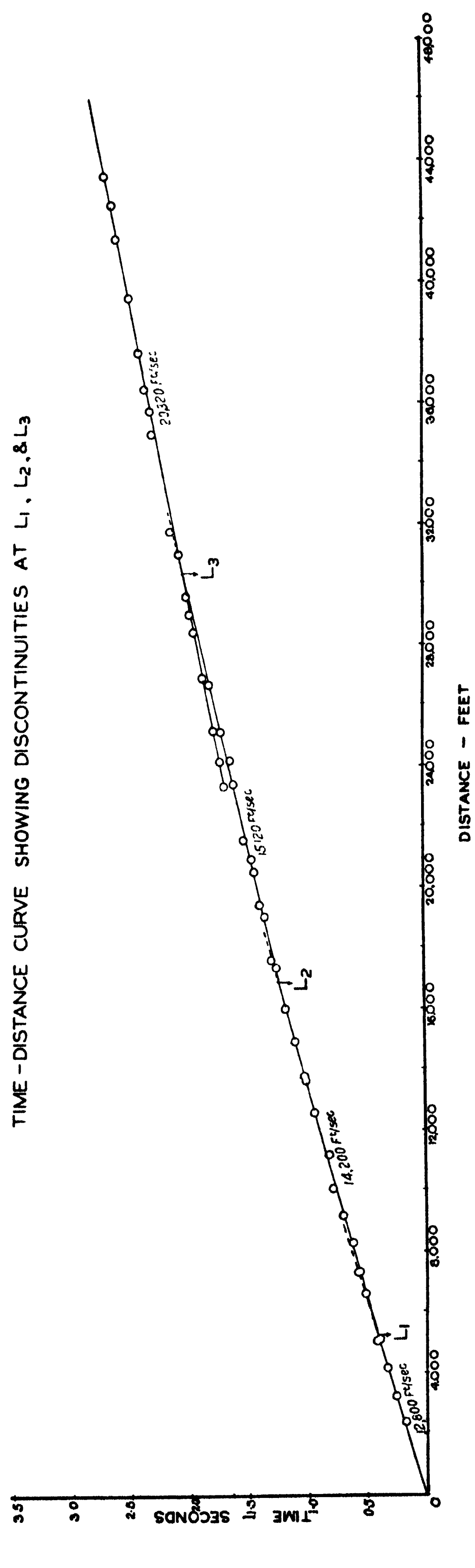


FIG. 3.

The Problem of Multiple Layers.

In practice there may be more than one discontinuity on the time curve indicating the presence of two or more layers overlying the solid layer under investigation. If the boundaries of the layers are assumed to be parallel, simple formulae can be deduced for calculating the depths from the time curve [3, 1932].

An example of a time-distance curve showing three discontinuities is shown in Fig. 3.

A set of seismograms showing the indirect wave-disturbance preceding that of the direct wave is given in Fig. 4. The onsets of the two disturbances are indicated on the seismograms by the arrows at *a* and *b*.

These seismograms were recorded in south-west Iran with the Jones Microid Seismograph; the natural period of the instrument was close on 0·8 sec. [5, 1933]. The average value of the velocity in the overburden was approximately 9,500 ft. per sec., and the value in the lower layer was about 15,500 ft. per sec. The average depth of the lower layer was 1,100 ft.

III. Recent Developments

The linear profile method invented by Mintrop is not suitable for large-scale exploration work, and other methods have been devised for this purpose.

There are two methods which have proved extremely useful and deserve special mention. These are the fan method developed in the Gulf Coast area for the search of salt-domes, and the arc method developed for reconnaissance work in the oilfields of Iran.

The Fan Method.

A good example of this method of exploration is given in an article by E. E. Rosaire and O. C. Lester, Jr., in the *Bulletin of the American Association of Petroleum Geologists*, **16**, no. 12, Dec. 1932. The article is titled 'Seismological Discovery and Partial Detail of Vermilion Bay Salt Dome, Louisiana'. The detectors are spread out fan shaped at different distances from the explosion point. A network of these fans is arranged to cover the area which is to be explored.

Fig. 5, taken from Messrs. Rosaire and Lester's paper, shows the network of fans in the survey of Vermilion Bay. The time of the first arrival is recorded at each observation point. All the times are plotted on one time-distance chart. Normal paths give times which lie approximately on a straight line, or on a smooth curve showing slight curvature. Abnormally short-time paths are indicated by large deviations from the mean line. Often these deviations amount to many tenths of seconds, and are unmistakable indications of the presence of salt-domes. The Vermilion Bay refraction fan time-distance curve is shown in Fig. 6.

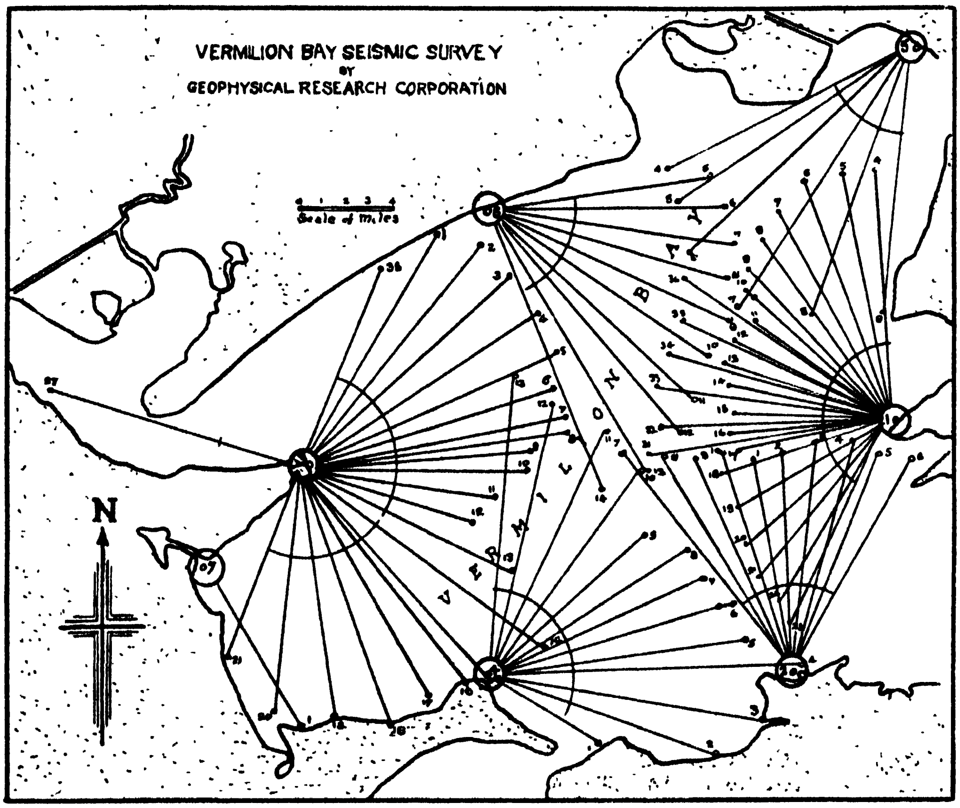


FIG. 5.

The points marked with crosses represent abnormally short-time paths and indicate the presence of a salt-dome between the particular explosion point and the corresponding observation stations.

The next step consists in detailed examination of the particular area defined by the reconnaissance fans, so that the top and the flanks of the dome can be accurately located. For this purpose the Mintrop linear traverse method is used.

The Arc Method.

This method was developed by the writer in connexion with an extension survey of the Haft Kel oilfield in Iran at the end of 1930.

A full account of the method is given in the *Proceedings*

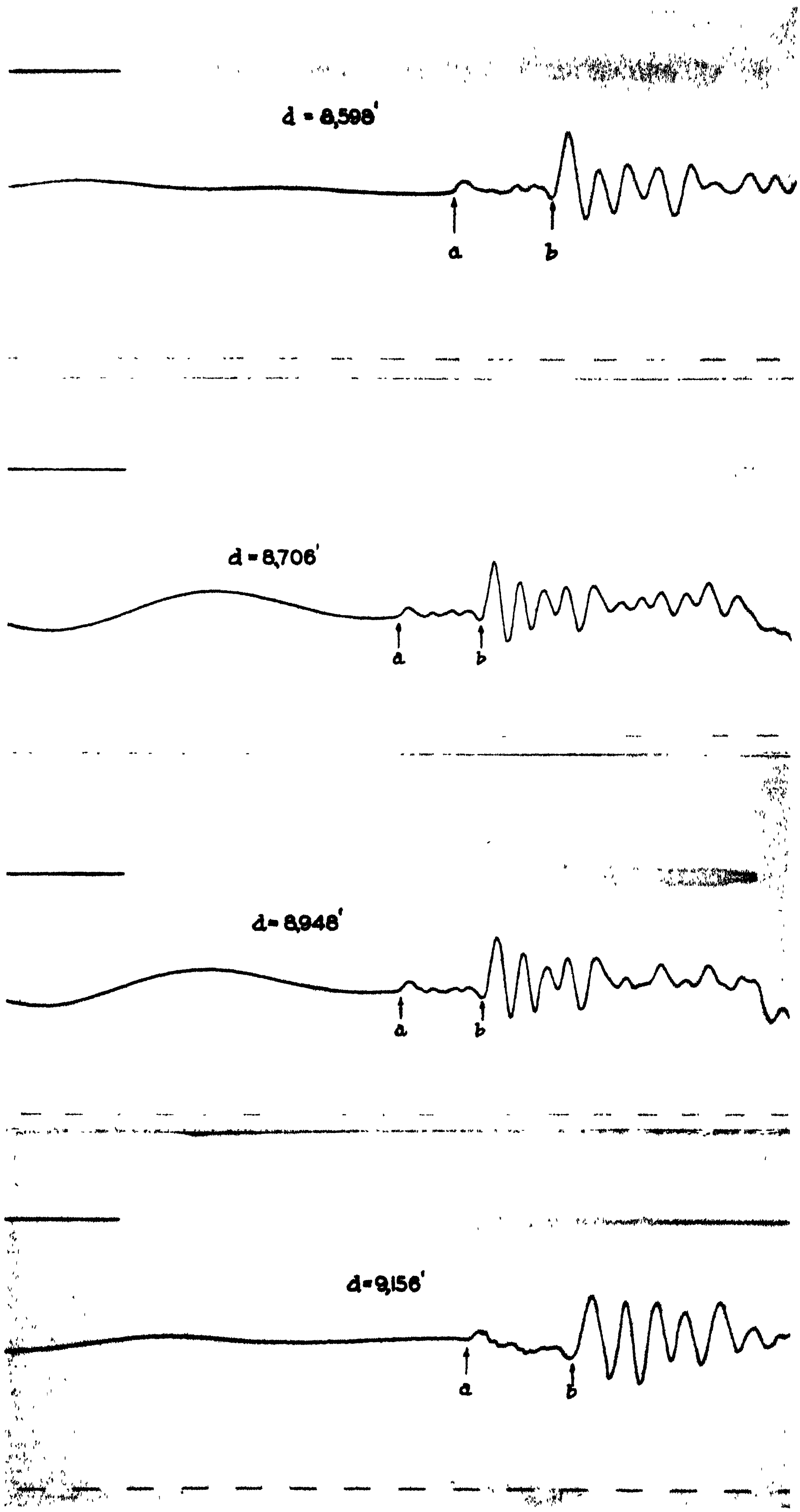


Fig. 4

of the World Petroleum Congress, London, 1933 [4]. In this method the detectors are arranged on the ground at approximately equal intervals on an arc of a circle of large radius. The length of the radius is governed by the depth and the velocity ratio. The charge of gelignite is fired at the centre of the circle and the times of first arrival observed at each detector station.

It is clear from (6) that the time will be a minimum at the point where H is least. This is immediately over the axis of the anticline; from this point the time will increase continuously down either flank of the structure.

Fig. 7 shows an arc-time curve, together with the corresponding profile determined from well data in the Haft Kel oilfield in south-west Iran.

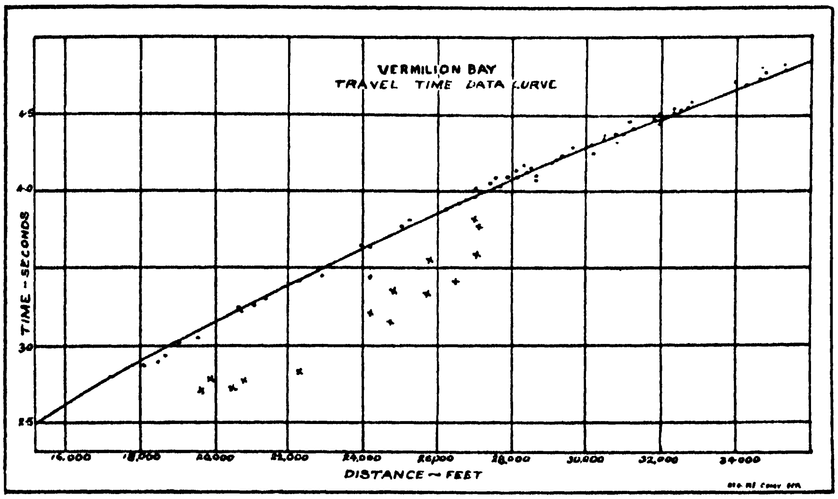


FIG. 6.

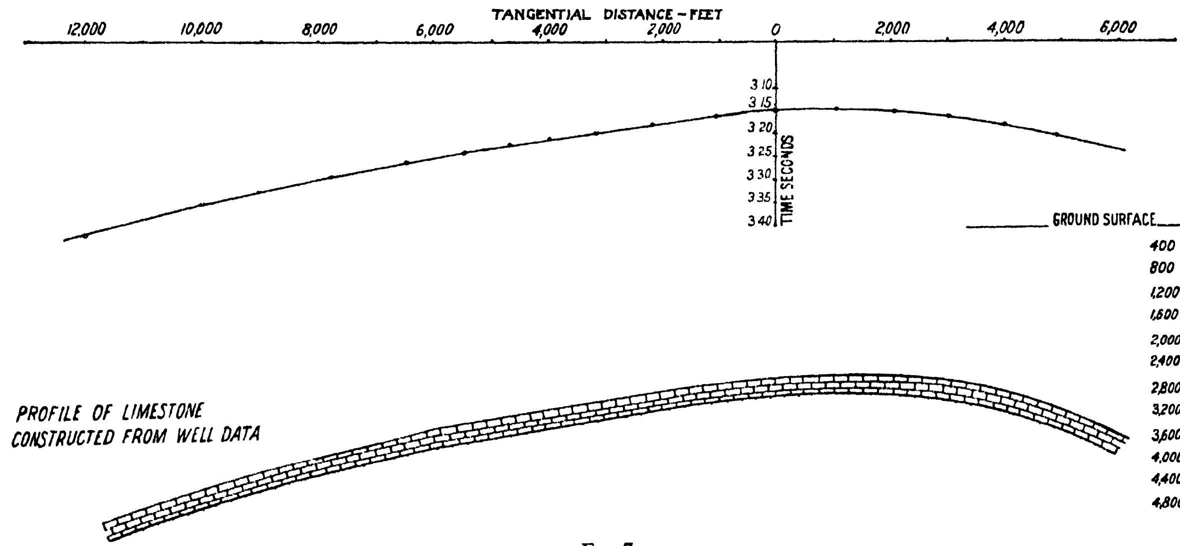


FIG. 7.

It can be shown that, to a first approximation, the travel time at any point on the arc can be expressed in the form

$$t = a+\frac{b}{v_L}+cH, \tag{6}$$

where b = the radius of the arc,

v_L = velocity in the solid layer,

a = quantity depending on the normal depth at the shot point and the average value of the elastic wave velocity through the overburden,

c = a quantity depending on the average value of the elastic wave velocity through the overburden.

Isochron Contour Maps.

For the purpose of detailed mapping with this method a number of arcs are surveyed at two- or three-mile intervals. These arcs are then linked together by linear traverses and all times are reduced to a common datum point.

It is necessary to know the value of the velocity v_L very accurately, and several determinations have to be made on linear traverses of suitable lengths.

The expression (6) can be put in the form

$$t' = t-\frac{b}{v_L} = a+cH. \tag{7}$$

The right-hand side of this equation depends only on the depths at the transmitting and receiving points, and on

the average values of the elastic wave velocities through the overburden [2, 1935].

To reduce the time t' in (7) to another datum point it is only necessary to change the value of the constant a. Thus if an arc with shot point O_1 intersects a line with shot point O_2 at a point P, we can reduce the times on the line to refer to the shot point of the arc.

We have for the arc

$$t'_{P_1} = t_{P_1} - \frac{O_1 P}{v_L} = a_1 + cH, \tag{7 a}$$

and for the line

$$t'_{P_2} = t_{P_2} - \frac{O_2 P}{v_L} = a_2 + cH. \tag{7 b}$$

To reduce the t' times on the line to refer to the shot point of the arc it is necessary to change a_2 in (7 b) to a_1. This is effected by adding the amount $(t'_{P_1} - t'_{P_2})$ to all values of t' on the line. In a similar manner times on other lines and arcs can be reduced to refer to O_1. Having reduced all times to the common datum point O_1, it is a simple matter to construct the isochron map of the underground structure.

The time at any point on the map will be related to the normal depth at that point by $t' = a_1 + cH$.

The vertical depth contour map can be constructed from the isochron map by a simple geometrical method when the values of the two constants a_1 and c are known.

IV. Values of Compressional Wave Velocities in Various Rocks

The following group of values for the compressional wave velocities are given by Salfeld [1, 1928].

1. 600 to 800 metres per sec.; rubble, gravel, sand loess.
2. 1,800 metres per sec.; clay, clayey sandstone.
3. 2,200 to 2,400 metres per sec.; slightly calcareous marl, siliceous sandstone, slightly calcareous sandstone.
4. 3,200 to 3,800 metres per sec.; calcareous marl, calcareous sandstone, hard clay slate.
5. 5,000 to 6,200 metres per sec.; limestone, dolomite, gypsum, anhydrite, salt, metamorphic rocks, massive rocks.

The following values have been determined in England and Iran by the Geophysical Staff of the Anglo-Iranian Oil Company:

Clay	about	5,000 ft. per sec.
Chalk	,,	10,000 ,, ,,
Calcareous sandstone	,,	11,000 ,, ,,
Gypsum	,,	13,500–14,000 ft. per sec.
Anhydrite	,,	14,500–15,000 ,, ,,
Salt	,,	15,500–16,000 ,, ,,
Limestone	,,	17,500–20,000 ,, ,,

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REFLECTION METHOD OF EXPLORING SUBSURFACE GEOLOGY

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General

THE utilization of seismic waves in mapping subsurface strata depends on physical phenomena closely akin to those observed in that branch of optics dealing with reflected light. In general, if an elastic wave travelling in any medium encounters changes in elasticity or density, or both, within the medium through which the wave travels, phenomena of reflection, refraction, and sometimes diffraction occur. The paths of such waves resemble those of light and of sound.

As the name suggests, seismic exploration by the reflection method is concerned only with that part of the wave energy which is reflected or turned back at the contact surfaces between subterranean formations possessing different physical properties.

The elastic waves utilized in subsurface exploration are commonly called 'sound' or 'seismic' waves. The waves are caused by a charge of high explosive fired a few feet beneath the earth's surface.

The simple theory of the reflection method is best illustrated by the well-known echo method of submarine sounding. This is illustrated in Fig. 1. Here a sound wave, usually of audible frequency, is transmitted from one part of a ship's hull, downward through the water, and reflected back, as indicated by the arrows, to a receiving device in another part of the hull.

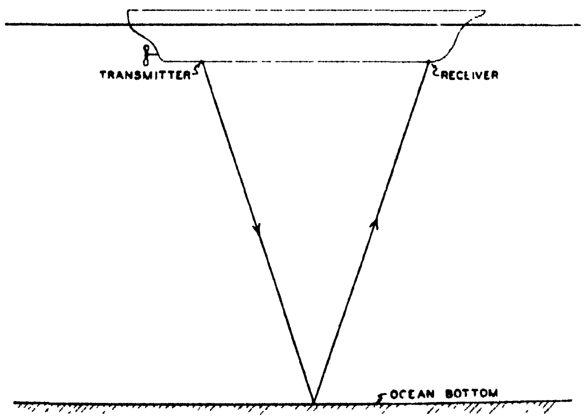

FIG. 1. Depth-finding by reflected sound.

In one embodiment of this method the total time of travel of the reflected waves, from transmitter to ocean bottom and back to the receiver, is measured. The velocity of sound in water being known, the depth of the reflecting boundary, which, in this case, is the bottom of the ocean, is readily calculable. This method has reached a high degree of development and, at the present time, direct reading instruments are available which give a continuous indication of the depth of the water while the ship is in motion.

No such ideal result has been accomplished in determining the depth of subterranean reflecting boundaries, due to basic differences between the conditions under which the operations have to be carried out in the two cases. In the early attempts at subterranean exploration work it was natural to seek to apply the principles that were then being successfully used in submarine sounding. Experience showed, however, that these were totally inapplicable, and it became necessary to develop an entirely new and radically different technique before success in subterranean exploration was achieved. The fundamental differences between the problem of ocean-depth sounding and that of subterranean exploration may here be set forth briefly as an aid in visualizing the problems involved in developing methods and equipment for commercial exploration work by the reflection method.

In submarine soundings we are dealing exclusively with water as a medium for transmitting the wave energy. Water is a highly elastic medium and transmits wave energy with very little absorption. Also, the velocity of sound in water is nearly uniform, and such variations as occur can readily be calculated from easily obtainable data. Furthermore, water being entirely lacking in rigidity transmits only simple compression waves, and in ocean soundings only a single reflecting boundary is involved. These ideal conditions greatly simplify the problem incident to ocean sounding and make possible the present remarkable speed and accuracy of the method. This simplicity led to false hopes and wasted effort in the early experimental attempts to apply the method to subterranean exploration.

In subterranean work the following conditions are encountered which do not occur in marine work:

1. The earth is a non-homogeneous medium, and the velocity of elastic waves passing through it varies from place to place both vertically and horizontally.
2. Transmission characteristics of most sedimentary formations are relatively poor, in consequence of which enormously greater energy radiation from the source is required.
3. Under most conditions the character of reflecting boundaries is such as to give a much lower coefficient of reflection than is obtained from the bottom of the ocean, so that it becomes necessary to work with very small amounts of reflected energy.
4. The earth possesses the characteristics of a solid in that it manifests a certain degree of rigidity; in consequence of this, both compression waves and transverse waves are generated at the source, while in water only compression waves are generated. Transverse waves travel at a lower velocity than compression waves, and hence there arises a disturbing factor in the reception and identification of reflected waves in subterranean work. Further, when either one of these types of waves impinges upon the boundary surface between two strata having different physical properties, each in turn is resolved into two components, one being of the compression type and the other the transverse type, and a certain amount of energy of each type is reflected back towards the surface, further complicating the problem of reception and identification of the individual reflected events.

5. A further condition of considerable importance in subterranean work grows out of the condition illustrated in Fig. 2, which represents a more or less typical section of sedimentary deposits. Here, a relatively thin layer, *a*, not infrequently called by geologists the weathered layer, rests upon a relatively more compact deposit, *b*. Because

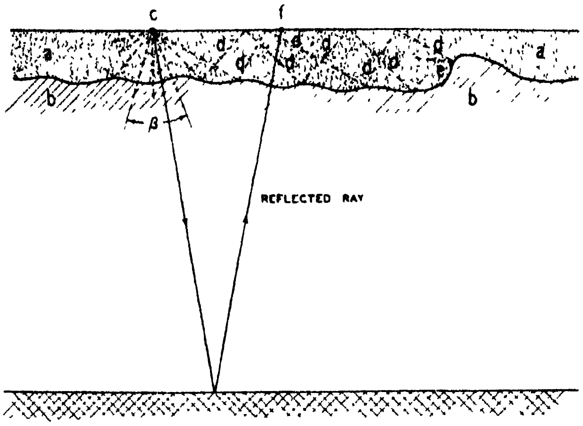

FIG. 2. The main reflection from the lower layer tends to be obscured by multiple reflections from the base of the weathered layer.

of its more consolidated nature, and due also partly to the greater pressure to which the formation *b* has been subjected over a long period of time, the velocity of sound in medium *b* will usually be much greater than that in medium *a*. If now a source of sound be located at a point *c*, and radiates therefrom in all directions, it will be seen that for the most part this radiant energy strikes the boundary surface between *a* and *b* at rather oblique angles. It is a well-known fact that when an elastic wave is travelling in any medium and impinges obliquely beyond a certain critical angle on a boundary surface of an adjoining medium of much higher propagation velocity, total reflection occurs. Since under practically all conditions the velocity of sound in medium *b* may be several times that in medium *a*, all of the energy radiated outside of a relatively small angle β will be totally reflected back towards the surface as shown by the arrows, *d*, *d*. These waves, on reaching the surface, are again reflected downward at an angle and, in general, reflected again and again, as shown by the zigzag lines. In consequence of this phenomenon the greater part of the energy radiating from the source is confined to the surface layer, and is ultimately dissipated therein. This phenomenon is analogous to the confinement of a light beam within a bent quartz rod, and is due to total reflection at the boundary surfaces between the quartz and the surrounding air in which the velocity of light is much higher than in quartz. Further, due to the variable character of medium *a*, numerous reflections, more or less horizontally directed, occur as at *e*. Any detector of sound waves, *f*, that may be set in the surface of the ground, will be actuated by these relatively violent disturbances for a long period after the sound emanates from the source. These disturbances are superimposed on relatively feeble reflected waves coming from the deeper horizons and so render their reception and identification difficult.

6. Under many conditions the source of sound embedded in the ground generates an air wave as well as an earth wave, and this air wave, radiating in all directions from the source, is frequently a disturbing influence on the seismogram.

7. Finally there exists the so-called Rayleigh wave, which is a surface phenomenon. It often has much energy and travels with low velocity, often not over 200 to 300 metres per sec. It is often a source of interference with the relatively feeble reflected waves under observation.

In consequence of the above, the methods and equipment that have been found so remarkably effective in ocean sounding prove to be of no value whatever when applied to the study of subterranean formations.

The successful development of the reflection method depends on means that have been devised for successfully minimizing the various undesirable radiation components above described. Three measures of prime importance which have contributed to this result are:

1. The use of relatively short shooting distances, that is, small angles of incidence and reflection, which greatly minimizes disturbances that would otherwise result from splitting up of the reflected wave into components embracing a large percentage of their energy in transverse waves, and also avoiding the relatively high dissipation of energy that takes place when these reflected waves travel at an oblique angle across stratified deposits.

2. The use of deeply planted explosives, or shots, which places the source down below the greater portion of the very low velocity surface formation, thereby avoiding, in a large degree, the effects of total reflection above described.

3. The development of effective filtering devices which give the equipment a high degree of selectivity to the reflected waves.

Experience shows that reflection seismograms are better if the shooting distance is kept below about 1,000 metres, but at less distance there is little difference, except when working quite shallow horizons, in which case still further shortening of the shooting distance is helpful. The relative intensities of the several surface waves, and the velocities at which they travel, vary so much from place to place that it is not possible to adopt any general rule as to the shooting distances that will give maximum freedom from undesired effects; this can only be determined by trial records in any particular locality, after which the optimum distance for that locality can be adopted for subsequent shooting. In commercial practice to-day, probably more than 90% of the shooting is done at distances between 0 and 1,000 metres.

Typical Field Procedure

A schematic arrangement of apparatus for reflection shooting is shown in Fig. 3. Here, *I* is the first shotpoint where a suitable charge of explosive is fired at a predetermined time; *a* is the communication line used both for

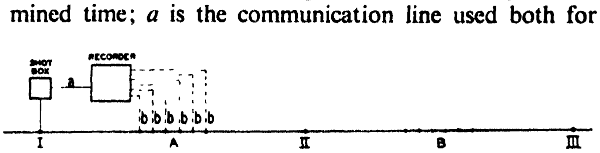

FIG. 3.

signalling between recorder station and the shot-firing station, and for transmitting the shot signal to the recorder. The lines *b*, *b* connect the recorder to the sound detectors, at station A, where there are usually 6 of these detectors in a set. The distance between the shotpoint and the centre of the detector group will usually be less than 1,000 metres, while the span embracing the group of detectors will usually range from 50 to 300 metres.

The usual procedure is to lay out a line of shot stations 1,000 metres apart, for example, and make set-ups of the

FIG. 4 Automotive equipment for reflection party

1. Drilling rig
2. Water truck for rig
3. Instrument truck
4. Shooter's water truck
5. Shooter's car
6. Party chief's car
7. Surveyor's car

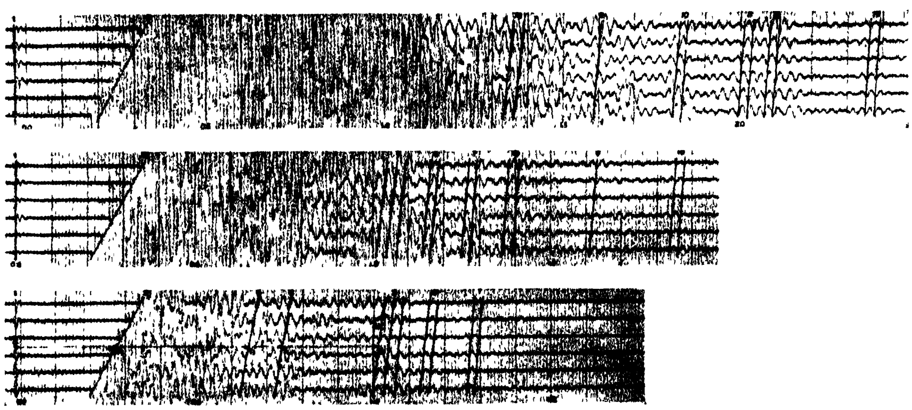

FIG. 7

detector group midway between the shotpoints. Each detector set-up is shot from the two nearest shotpoints in opposite directions in order to permit more accurate interpretation of the data as will be described later. On each set-up it is customary to shoot several times from the same shot hole, small charges being used for obtaining reflected waves from shallow horizons and heavier ones from the deeper horizons. As a rule from 3 to 5 shots are required to embrace all horizons down to about 5,000 metres. When shooting from shot station I has been completed, the shooter moves to shot station II on the other side of the detector set-up, and the same set-up is shot from the opposite direction. The shooter then remains at station II while the detector set-up is moved to station B, and so on. This procedure has two important advantages, viz., it yields two depth determinations for each shot station, and each detector station is shot from opposite directions, an important consideration, as will later appear.

The depth of the shot holes is of prime importance in securing satisfactory reflection results. In most areas the usual practice at present is to drill the shot holes to depths ranging from 15 to 30 metres, although in some cases, particularly where it is necessary to get the shot below deep surface sands or other low-velocity beds, still deeper holes are used. This is essential for reducing effects of surface travelling waves discussed above. In many cases, particularly where the holes are drilled in sand, it is necessary to case the holes before shooting, and some companies make it a standard practice to case all holes to ensure that they will stand up throughout the shooting operations. For the most part, $2\frac{1}{2}$ to 3 in. casing is used. The shots are stemmed with water in order that the same hole may be shot as many times as desired.

The amount of explosive charge required will vary greatly in different places, and to some extent from point to point along any line. Sometimes a single percussion cap will suffice and the charge required may range upward to several kilograms of explosives. Rarely will more than 4 or 5 kg. of explosive be required.

The operator in charge, guided by immediately preceding experience, will first use a charge of about the mean size required at the preceding adjacent shotpoints. The resulting seismogram is immediately developed and used as a guide in determining the subsequent charge for that shotpoint to give information over the desired range of depth with a minimum number of shots.

At each station along the line the seismograms give information which can be used for determining the depth and position of the points of reflection on various horizons. Such points of reflection are usually, although not always, somewhere below a region between the shot station and detector station.

In some cases, where greater accuracy or detail is considered of sufficient importance, there is an interchange of shot and detector stations. In this procedure the first series of shots will be taken as described above, then the relative position of the shot station and detector station is interchanged and a similar series of shots taken. The advantage of this is that the points of reflection in both cases are coincident, permitting somewhat greater theoretical accuracy than is obtainable from the procedure first described. This is a slower and more expensive procedure, however, and, in the opinion of the writer, the extra expense is not warranted, except in special cases, as when detailing important areas characterized by difficult subsurface conditions.

Automotive Equipment

A complete set of transportation units required for the seismograph party is shown in Fig. 4. This embraces a portable drilling rig, usually of the rotary type; a tank wagon to service the drilling rig; a recorder truck to transport the recording and amplifying equipment; a tank wagon to serve as a shooter's truck and to provide water for stemming the shots; a surveyor's car and one or two additional passenger cars for transporting personnel of the party.

Organization and Personnel

The personnel required for a representative seismograph party will vary somewhat according to conditions and individual views as to what constitutes the most efficient organization. For the most part, a representative party may be considered as made up of the following personnel:

- Geophysicist.
- Assistant geophysicist.
- Party chief.
- Instrument operator.
- Shooter.
- Two shooter's assistants.
- Surveyor.
- Two surveyor's assistants.
- Chief wireman.
- One or more assistant wiremen.
- Driller.
- Two driller's assistants.

The chain of responsibility in a typical seismograph party is shown in the organization chart in Fig. 5.

Instruments and Apparatus for making Reflection Seismograph Surveys

A typical instrument set-up for making reflection seismograph surveys is shown in principle in Fig. 6. A photographic recorder, generally embracing 5 or 6 galvanometer elements, is used. The elements may be of either the Einthoven or d'Arsonval type. The time scale is placed on the seismogram by means of a light shutter consisting of a rotating slotted disk, driven at a constant speed by a small synchronous motor, operated from a tuning fork. The slots in this disk are usually adapted to give a time line on the film every 0·01 sec., and it is the usual practice to have every tenth slot wider than the others to give a relatively heavy line every 0·1 sec. to facilitate the scaling of time on the seismogram. Means equivalent to the 'shot-kick' transformer are provided whereby the instant of firing the shot is recorded on one or all of the traces on the seismogram. In its simplest embodiment this shot-kick mechanism is coupled to the telephone circuit used for communication between the shot and recorder stations.

At the present time it is usual to determine the time of firing the charge, not from the time of firing the cap, as was formerly done, but by looping an electrical circuit around the charge and recording on the film the instant of the breaking of this circuit. This arrangement is provided in the hook-up shown in Fig. 6, as will readily be seen by tracing out the wiring diagram. This eliminates any error due to time lag in the cap.

Sound detectors are connected with the recording unit through independent lines passing through the filter and amplifying unit, both of which are preferably combined in a single unit for compactness and efficiency.

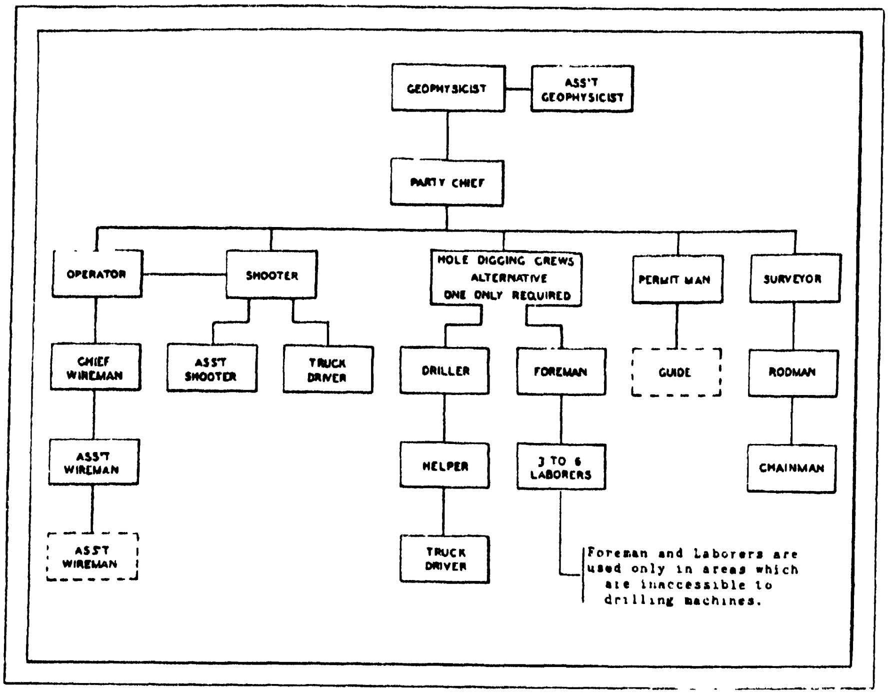
GEOPHYSICIST
ASS'T GEOPHYSICIST
PARTY CHIEF
OPERATOR
SHOOTER
HOLE DIGGING CREWS ALTERNATIVE ONE ONLY REQUIRED
PERMIT MAN
SURVEYOR
CHIEF WIREMAN
ASS'T SHOOTER
TRUCK DRIVER
DRILLER
FOREMAN
GUIDE
RODMAN
ASS'T WIREMAN
HELPER
3 TO 6 LABORERS
CHAINMAN
ASS'T WIREMAN
TRUCK DRIVER
Foreman and Laborers are used only in areas which are inaccessible to drilling machines.

FIG. 5.

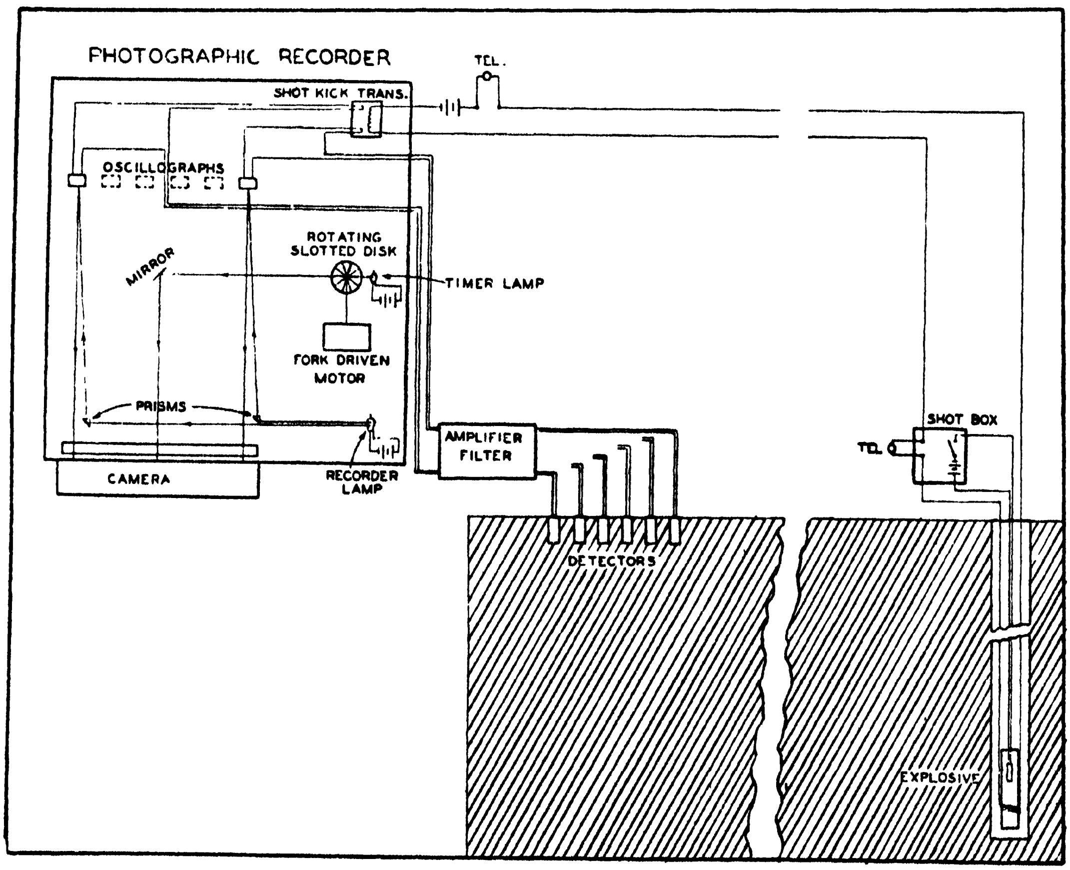
PHOTOGRAPHIC RECORDER
TEL.
SHOT KICK TRANS.
OSCILLOGRAPHS
MIRROR
ROTATING SLOTTED DISK
TIMER LAMP
FORK DRIVEN MOTOR
PRISMS
CAMERA
RECORDER LAMP
AMPLIFIER FILTER
DETECTORS
SHOT BOX
TEL.
EXPLOSIVE

FIG. 6.

Electrical Seismograph

The electrical seismograph unit described above has virtually replaced the older mechanical type of seismograph for reflection work. One of the reasons for this is the greater adaptability of the electric type to filtration, this principle being of vital importance in suppressing the horizontally travelling waves so that the relatively feeble reflected waves will stand out with sufficient clearness on the seismogram.

Experience has shown that most of the energy of reflected events is carried on wave-lengths corresponding to frequencies varying between about 40 and 60 cycles per sec., whereas most of the horizontally travelling energy is usually carried on longer wave-lengths. By adjusting the filter to pass only a narrow band of frequencies between about 40 and 60 cycles, the horizontally travelling waves can generally be suppressed to a sufficient degree for practical purposes.

Interpretation of Seismograms

We shall now examine the procedure to be followed in analysing and interpreting the seismograms obtained as above described. Fig. 7 may be regarded as typical of seismograph records obtainable throughout most of the Texas-Louisiana Gulf Coast area. These seismograms were taken on a shooting distance of 450 metres with detector spacing of 50 metres. The following outstanding events will be noted:

First, we observe the shot-kick which is recorded on all of the traces at 1; next we encounter a large burst of energy at 2, which is produced by the series of more or less direct travelling waves between shot and detector stations, including surface and compression waves and other components as described above. Succeeding these waves are a series of more or less distinct events, 3, 4, 5, &c., occurring on the seismogram. These are reflected waves coming from horizons at successively greater depths. Their definite identification as reflected waves, rather than horizontally travelling waves, is made from the fact that they line up across the film at a very small angle as compared to the large angle characterizing the direct travelling waves.

As a basis for interpreting these records in terms of subsurface geology, we derive from them certain time data as follows:

1. The time, T_2, elapsing between the shot-kick 1 and the first main event 2 on the seismogram.
2. The various over-all times elapsing between the shot-kick and the several reflected events on the seismogram. These will subsequently be referred to as T_3, T_4, T_5, &c.
3. The interval time, this being the difference in time between the arrival of a particular reflected event at the detector station nearest the shot and the arrival of the same event at the station farthest from the shot, as illustrated on event 5 of Fig. 7. These interval times will be referred to as t_3, t_4, t_5, &c.

In reflection work the times to the first or main events on the seismogram are useful only in making corrections for the surface or weathered layer, but the over-all time, T, from the shot to reflected waves, and interval time, t, are basic to the interpretation of reflection records.

We are now ready to proceed with the analysis and interpretation of the above data.

The essence of the analytical problem is shown in Fig. 8. Here a shotpoint is located at A and a group of detectors is spread uniformly between the positions F and G, thereby giving a total detector span equal to the distance b, with the centre at C. The distance from the shotpoint to the centre of the detector group is a. A reflected wave arrives at point C, after reflection from point B, on a reflecting bed which, in general, is inclined to the horizontal at some

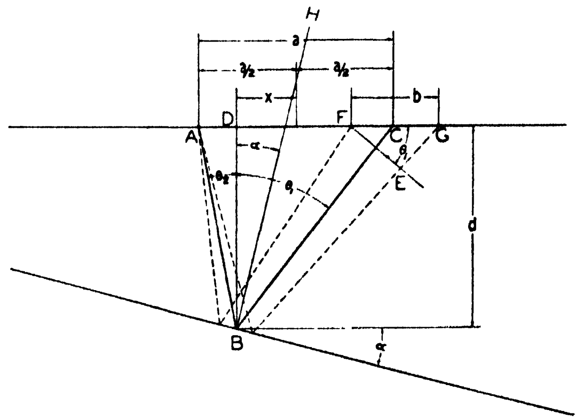

FIG. 8.

angle α. The line BD is a vertical line passing through the point of reflection, B, and the angle DBC, designated as θ_1, is called the angle of emergence. The angle θ_2 is the corresponding angle when shotpoint and detector stations are interchanged. The line BH is drawn through B, normal to the reflecting surface. It will be evident, on inspection of the diagram, that the angle GFE is also equal to the angle θ_1, where FE is at right angles to BC.

We are now concerned with the following quantities:

1. *Quantities known from the line survey.* These comprise the distance, a, between the shot station and the centre of the detector set-up, and b, the over-all span of the detector group.
2. *The mean velocity*, V, of sound in the earth section overlying the reflecting boundary. This value must be known from prior experience in the area under exploration, or it must be derived from special procedure to be described later.
3. *Quantities obtainable from the seismograms.* These embrace T, which is the over-all travel time of the reflected wave from A to C via the reflection-point B, and t, which is the difference in time of arrival of the reflected wave at the nearest and farthest detectors at F and G respectively.

The above are the known values of the working equations. The unknown values, with which we are ultimately concerned, are:

α, the angle of dip of the reflecting bed;
x, the horizontal displacement of the reflection-point B, with reference to the centre of the set-up;
d, the depth in a vertical direction of the point of reflection B.

As an intermediate step in arriving at these latter values we must, however, evaluate θ_1 and θ_2.

It will be observed that in stating the premises of the problem we have assumed that the reflecting layer below shotpoint and detector set-up extends with a constant dip, while, in general, in reconnaissance work this will not be the case. It can, nevertheless, be shown that the dip of the

reflecting bed, below the shooting line, will be given by the data obtained with a degree of accuracy satisfactory for practical purposes.

Again referring to Fig. 8, we observe that at the instant at which any particular wave arrives at the nearest detector, F, the line $\overline{FE}$ constitutes a portion of the wave front of the reflected wave. It is here assumed that this segment of the wave front is a straight line; also, it is assumed that the travel paths $\overline{AB}$ and $\overline{BC}$ are essentially rectilinear, and that b is small compared with d. No errors of consequence occur when these assumptions are made. The following relationships will be obvious:

$$\sin\theta_1 = \frac{\overline{EG}}{\overline{FG}}$$

$$\overline{FG} = b \quad \text{and} \quad \overline{EG} = Vt'.$$

$$\therefore \sin\theta_1 = \frac{Vt'}{b}.$$

Since V and b are known, it is necessary only to determine the value of t' in order to derive the value of θ_1. This is done by firing a shot at point A, and receiving the reflection from B on the detector group extending from F to G. From the record thus obtained, the difference in time of the arrival at the station G and station F gives the desired value of t'. In the general case it is necessary to interchange the positions of the shot and detector set-up, the shotpoint now being placed at C and the detector set-up having its centre at A. Another record is then taken with the shot fired at C and the difference in time, t'', is taken from the record as the time between the arrival of the reflected wave at the farthest and nearest detector. The geometry of this interchanged set-up will be identical in principle with that shown in Fig. 8, so that it is not necessary to draw a separate figure to illustrate it.

(*a*) **Calculation of Angle of Dip of Reflecting Horizon.** Proceeding now with the analysis of the data it will be seen from Fig. 8 that the following relationships hold:

$$\left.\begin{aligned}\sin\theta_1 &= \frac{Vt'}{b}\\ \sin\theta_2 &= \frac{Vt''}{b}\end{aligned}\right\} \tag{1}$$

These values are fundamental to all subsequent calculations. It will also be observed from geometrical considerations that

$$\theta_1 - \alpha = \theta_2 + \alpha.$$

$$\therefore 2\alpha = \theta_1 - \theta_2$$

$$\alpha = \frac{\theta_1 - \theta_2}{2}. \tag{2}$$

Since θ_1 and θ_2 are both derivable from equations (1), the angle of dip, α, of the reflecting boundary is calculated from equation (2). If α comes out positive, the reflecting horizon is dipping in the direction from shotpoint to detector station, and if negative, the direction of dip is opposite.

In deriving the above formulae we have assumed that the position of the shotpoint and detector group are interchanged for determining both t' and t''. Theoretically this would be the correct procedure, since in this case the points of reflection of the waves are the same for deriving both t' and t''. However, in practice it is usually sufficiently accurate and more economical to follow the procedure described on page 388. This presumes that the direction and magnitude of the dip are substantially the same at two adjacent reflection points several hundred metres apart. The data obtained from the seismograms will show definitely whether or not this is the case, and if not, the more accurate method of interchange of shot and detector may then be used.

(*b*) **Calculation of Position of Point of Reflection.** The length x is the horizontal distance from the reflection point to the midpoint between shot and centre of the detector group. From simple geometrical considerations we observe:

$$\tan\theta_1 = \frac{\tfrac{1}{2}a + x}{d}$$

$$\tan\theta_2 = \frac{\tfrac{1}{2}a - x}{d}.$$

$$\therefore \frac{\tfrac{1}{2}a + x}{\tfrac{1}{2}a - x} = \frac{\tan\theta_1}{\tan\theta_2} = r.$$

$$\therefore x = \tfrac{1}{2}a \cdot \frac{r-1}{r+1}. \tag{3}$$

values of θ_1 and θ_2 are derived from equations (1) ve, and thus the value of r, the ratio of the tangents, me known; hence equation (3) permits the calculation . If x comes out positive the shift of the reflection t is towards the shotpoint; if negative, the shift is rds the detector set-up.

) **Calculation of Depth of Reflection Point.** From Fig. 8 ll be seen that the total distance travelled by the wave shotpoint A to a detector at C via B is

$$L = \overline{AB} + \overline{BC} = d\sec\theta_2 + d\sec\theta_1 = VT.$$

$$\therefore d = \frac{VT}{\sec\theta_1 + \sec\theta_2}. \tag{4}$$

The value of V is known and T is taken from the seismogram, while θ_1 and θ_2 are obtained from equations (1) above, whence d is calculated from equation (4).

From the above it is evident that each shot-set-up combination is productive of both depth and dip determinations. Repeat the procedure at intervals along a surveyed line and the local variations of these quantities are found within the area explored. Two independent methods are available for evaluating these data for the purpose of obtaining the structural picture; namely, the 'Dip Method' and the 'Correlation Method'.

Dip Method. If we calculate the dip of the reflecting bed from equation (2) we can usually assume, with a fair degree of accuracy, that this value of dip persists over a considerable distance on either side of the point of reflection. If, for example, we make dip determinations at 500-metre intervals and assume that the measured dip persists for 250 metres on each side of the point of measurement, we can calculate the total change in elevation of the strata between adjacent reflecting points without regard to any direct correlation between reflecting beds at those stations. If it be true in any case that no reflecting beds persist from one point of measurement to the next, then this is the only method available for constructing the profile. In this case the dip of the reflecting bed for any particular reflected wave is determined as described above. A point is then spotted, as at A in Fig. 9, at the appropriate position along the line, and at a slant depth corresponding to the over-all time, T, for that particular reflected wave. Then a line is drawn through this point parallel to the calculated dip of the reflecting stratum at the point. A similar procedure is next followed for all other points on the diagram. It frequently develops that most of the reflected waves have come from local and discontinuous strata interbedded in

fortuitous fashion and related only by a general parallelism at any particular vertical section. From this observed parallelism we can draw a 'virtual profile', substantially paralleling the dip indicators, and this virtual horizon will give a fairly accurate picture of the subsurface structure, although it does not refer to a specific formation. Fig. 9 is a typical profile of Texas-Louisiana Gulf Coast formations derived by the dip method.

The relative merits of the correlation and dip methods have been a subject of considerable discussion, and at times sharp differences of opinion have developed as to the applicability of one or the other in certain areas. It is the view of the writer that all such discussions and opinions are of academic interest only. The records taken by the usual modes of field procedure give the main data for both methods of interpretation, and since each interpretation will, in most cases, lend increased support and certainty to the other, there is no warrant for deliberately discarding one or the other. If, as sometimes occurs, the interpretations by the two methods are definitely in conflict, we are then confronted with a case in which more field work is required to resolve the uncertainty. If, on the other hand, as is usually the case, the interpretations by the two methods are in substantial agreement, the geophysicist can then present his findings with greater confidence than if only one method is used. Since the cost of making the interpretations is but a fraction of the total cost of the seismograph operations, it appears that the small additional expense of the double check on the accuracy fully warrants the use of all information available from any set of seismograms.

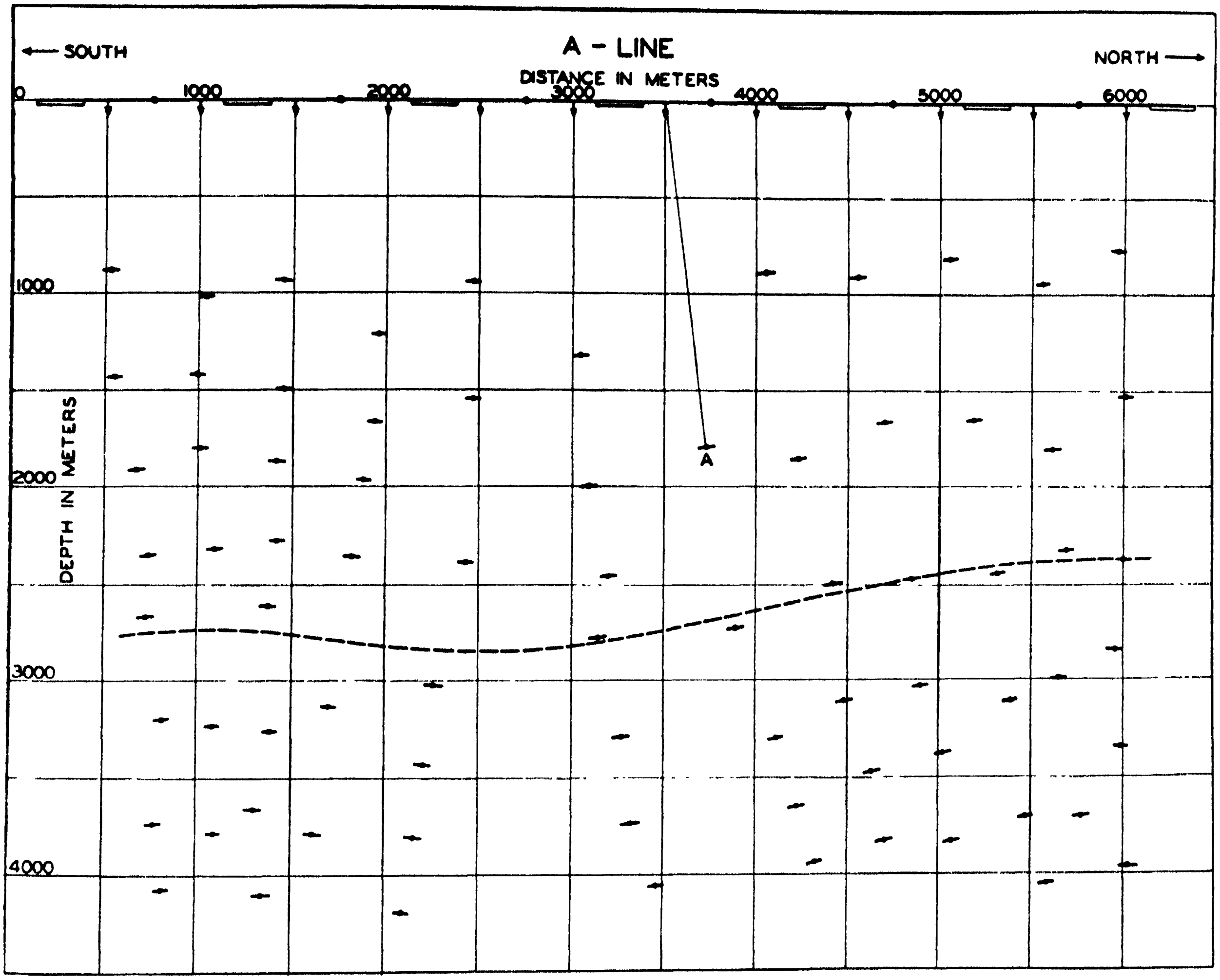

FIG. 9.

Correlation Method. In this method the depth of any particular reflecting stratum is calculated for any one point of observation by using equation (4). We then endeavour to identify the reflected wave from this same stratum on the seismogram taken at the next and succeeding stations on the line and calculate the depth at those stations. If we can definitely identify the corresponding waves, this method permits the ready and accurate profiling of the section. In certain cases, especially where there exist hard limestone horizons separated by relatively thick beds of shale or other soft formations, this can be done with virtual precision. Under such favourable conditions, little, if any, attention need be given to dip determinations. This procedure is known as the correlation method. In many cases, however, the identification of the corresponding reflected waves on successive set-ups is not immediately obvious, and in such cases the dips of the several strata are of great aid in making such identification.

Fig. 10 is a chart showing a section of Texas-Louisiana Gulf Coast formations characterized by many lenticular deposits of only local extent, but presenting a few strata

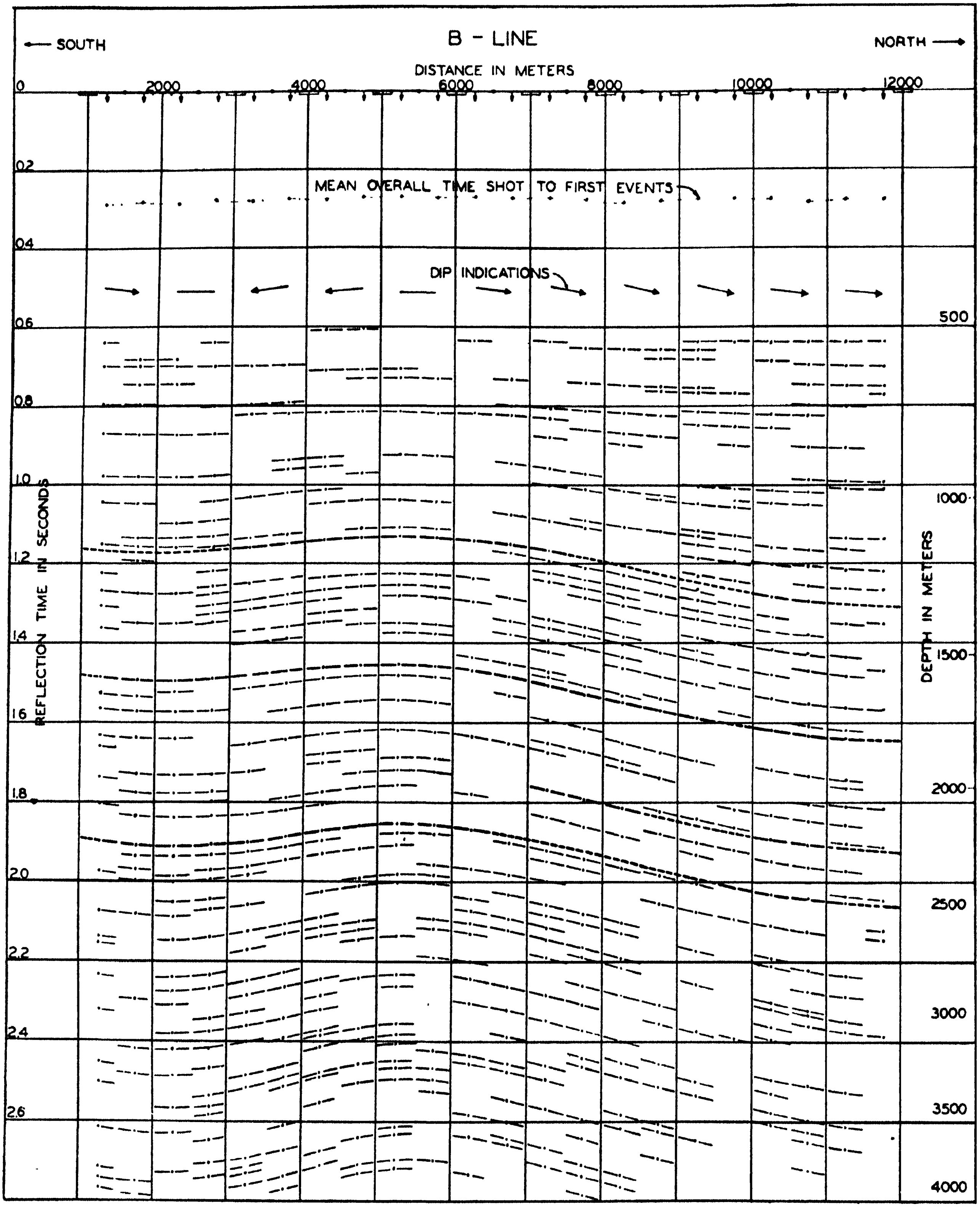
← SOUTH
B - LINE
NORTH →
DISTANCE IN METERS
0
2000
4000
6000
8000
10000
12000
MEAN OVERALL TIME SHOT TO FIRST EVENTS
DIP INDICATIONS
REFLECTION TIME IN SECONDS
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.2
2.4
2.6
DEPTH IN METERS
500
1000
1500
2000
2500
3000
3500
4000

FIG. 10.

of more or less regional extent. On account of the large number of reflecting strata, they have been first plotted as time strata; the total over-all time, T, from shots to reflected waves being shown on the left. At the top of the chart the direction and approximate magnitude of the dips as determined by the dip method are shown by the arrows. These dips will be seen to offer material aid, in many cases, where otherwise the correlation of the time strata might be obscure. On certain of the more definite horizons it is usual to convert the time strata into actual depth profiles by applying equation (4). The depth scale for this conversion is shown at the right-hand side of the chart.

Velocity Determination

Since the velocity of elastic waves in the earth varies greatly from region to region and also varies with depth in any particular area, the accurate determination of this velocity is of considerable importance. Two methods are available for this. The most direct and satisfactory method is to place a sound detector down in a deep well and measure the velocity from the surface down to a series of different depths. It is desirable to place the shot at some distance from the well, preferably at about half the usual distance between shotpoints and detectors in reflection shooting. This has the double advantage of taking account of the effect on the velocity of the waves travelling at an oblique angle with the formations as it actually does in most reflection shooting, and it also corrects automatically, for the effect of curvature of path due to change of velocity, with depth. It is important also to shoot on opposite sides of the well to avoid error due to deviation of the well from the vertical. This method gives very precise data on the velocity for the region contiguous to the well.

In many areas, however, no wells are available, and in such cases it is necessary to use another method for determining the velocity. A method available for this purpose is illustrated by Fig. 11. A shot is fired at the point A and

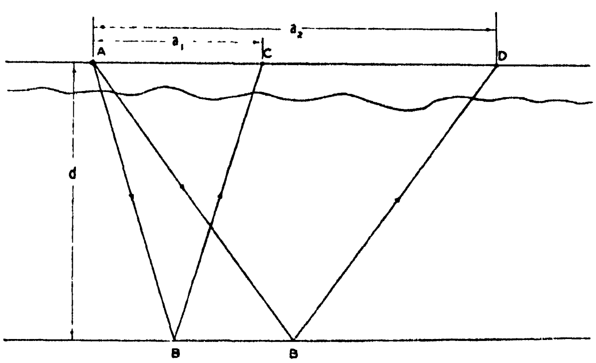

FIG. 11.

reflected events from the bed B–B are recorded at detector stations C and D. Here a_1 is the horizontal distance from A to C, and a_2 that from A to D, and d the depth of the reflecting bed. Further, if T_1 and T_2 are respectively the over-all times of travel of the reflected waves from A to C and A to D, and if V is the mean velocity, we have the following simple relationship:

$$V^2T_1^2 = 4d^2+a_1^2, \qquad V^2T_2^2 = 4d^2+a_2^2.$$

$$\therefore\ V^2(T_2^2-T_1^2) = a_2^2-a_1^2.$$

$$\therefore\ V = \sqrt{\left(\frac{a_2^2-a_1^2}{T_2^2-T_1^2}\right)}. \qquad (5)$$

This method, while theoretically very simple, leaves much to be desired from the standpoint of accuracy unless great precautions are taken. It will be seen that the denominator contains the difference between the squares of two quantities not greatly different in magnitude. A small error in measuring either of these quantities is therefore greatly magnified in the calculated value of V. In general, the greater the spacing of the two detector stations the greater will be the accuracy of velocity measurements. Obviously, in applying this method it is essential that the reflections take place from the same depth in both cases. This combination is often difficult to achieve and will be discussed later.

Further, small variations in the thickness of low velocity surface beds at C and D will, if not carefully corrected for, introduce large errors into the calculated value of V. Also in some areas, as in the Gulf Coast, if the points C and D are separated by a considerable distance, doubt may exist as to whether the reflected waves chosen come from the same bed. The following procedure has been found to minimize the difficulties mentioned and give results sufficiently accurate for practical purposes.

First a preliminary profile is run, about 2 km. in length, preferably about parallel to the geological strike so as to secure not only a nearly level horizon, but also to give greater assurance of nearly uniform velocity throughout the line. Depth determinations are made at sufficiently frequent intervals to eliminate doubt as to the continuity of the reflecting strata. If the strata are found to be continuous and virtually level, a reflection set-up is made with two detectors from 1 to $1\frac{1}{2}$ km. apart. A seismogram is then taken with the shot 100 or 200 metres from the nearest detector. The shot and detector stations are then interchanged and another seismogram taken. The mean values of the over-all times, T_1 and T_2, are then substituted in equation (5) and the velocity calculated. If the work is done with care, values of sufficient accuracy for most practical purposes can be thus obtained. Of course, a number of reflecting beds can be used on the same set-up so that the values of V at a number of depths can be obtained.

Corrections for Surface Irregularities

In many cases one of the chief sources of error in reflection seismograph work lies in the formations near the surface which comprise what is usually called the weathered layer.

This is shown in principle in Fig. 12. It will be seen that there is not only topographic relief on the surface, but the depth of the so-called weathered layer may vary greatly from point to point. It is a well-established fact that the velocity of sound in this weathered layer is very low in comparison with the velocity of the more compact shales

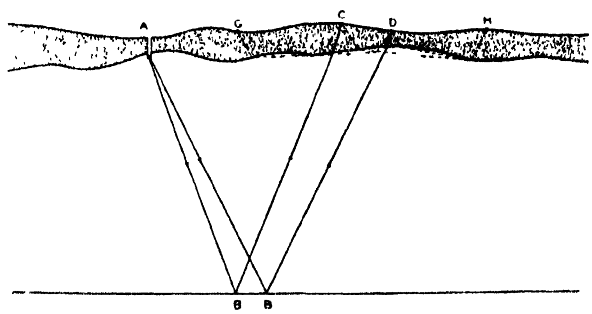

FIG. 12.

and clays immediately underlying it. Many instances have been found in which sound velocity near the surface has ranged between 200 and 500 metres per sec., whereas at depths below 100 metres or so the velocity will be between 1,000 and 2,000 metres per sec. It is obvious, therefore, that variations in the thickness and velocity of the weathered layer from point to point will introduce large variations in the travel time of reflected waves quite independent of the depth of the reflecting surfaces. Furthermore, local irregularities in the depth and velocity of the weathered layer immediately underneath the detector set-up will give rise to large variations in the interval times between the detector nearest the shot and the one farthest away. These variations may give rise to large errors in dip determinations.

In areas where the above described conditions prevail accurate reflection seismograph work requires that some correction for this source of error be made. Theoretically, it should be possible to correct more or less completely for such errors, and this result can be very closely approximated in practice provided a sufficient amount of so-called surface correction shooting is done at each station.

Too often, however, the effort to secure sufficient data to correct these errors will involve more time and expense than does the regular programme of reflection shooting, and the cost often becomes prohibitive.

The problem thus becomes in the last analysis largely an economic one, and the geophysicist in charge of the work must determine in individual cases how far he is economically justified in going in order to achieve a higher degree of accuracy in the final results.

The basic principle of making surface corrections is illustrated in Fig. 12. Here the reflection set-up in its simplest form may be regarded as comprising a shot at the point *A*, with recorders at stations *C* and *D* of reflected waves from points *B*, *B*. It will be seen that the reflected wave travelling to *C* passes through a greater thickness of the low-velocity weathered layer than does that part of the wave which reaches the detector *D*, and it becomes necessary to correct for the differences in time thus produced. For this reason a 'correction shot' is fired at a point *G*. It can be shown that the first waves reaching stations *C* and *D* are those that travel by indirect routes shown by the dotted lines. For more accurate correction a similar correction shot is fired at *H*, on the opposite side of the detector set-up, and in this case also the paths of sound waves first reaching the detector are shown by the dotted lines. If we have chosen the position of shot stations *G* and *H* correctly, so that the first wave reaching detectors at *C* and *D* do in fact travel by the indirect route indicated by the dotted lines, then these two correction shots furnish sufficient data to correct for the effect of the weathered layer with sufficient accuracy for all practical purposes. However, it may frequently happen that we would not know enough about the thickness of the weathered layer to enable us to determine the proper positions of the correction shotpoints *G* and *H* on the first trial, in order to fulfil the condition above stipulated, and this can only be determined after an examination of the correction records. It not infrequently happens, therefore, that proper surface corrections call for additional local shooting, and it is this possibility that often raises a serious economic question.

In a great many practical cases it has been found sufficient to dispense with the special correction shots and instead use the over-all times between shot and the first event on the record due to the direct travelling waves. These waves also travel by the indirect paths similar to the dotted lines of Fig. 12. In general, if the low-velocity surface layer is abnormally thick, these over-all times to the first wave on the record will be abnormally long, and vice versa. These over-all times, therefore, afford a rough measure of the thickness of the weathered layer and therefore of the surface correction necessary. For economic reasons it is desirable to use this simple method whenever local conditions will permit. If, however, widely varying thicknesses of the weathered layer are encountered from point to point, it will often become necessary to use the more expensive but more accurate method illustrated in Fig. 12.

A complete treatment of the subject of weathered-layer corrections would lead to more detail than present space limits permit. It may be said, however, that the entire problem of weathered corrections is fundamentally a problem of shallow contouring of the boundary between the weathered layer and the more compact clays and shales lying immediately underneath. Sometimes this boundary is sharp and well defined, and at other times it is composed of a more or less vague transition zone that may be as much as 50 or 100 metres in thickness. In most cases, however, the profiling of this very shallow boundary cannot be successfully carried out at the present time by reflection. It can, however, be done with sufficient accuracy for practical purposes by special applications of the refraction method of profiling.

Accuracy of Reflection Profiling

Four general groups of errors may be recognized as possibly affecting the accuracy of reflection seismograph profiling.

1. This group embraces errors resulting from uncertain topographic relief, and the various errors that may be inherent in instruments, such as time lag in the circuits, or apparatus, and errors of measuring time on the film. With modern equipment and procedure, however, these errors may be reduced to entirely negligible quantities.
2. Errors in determining vertical velocities.
3. Errors resulting from uncertainties in the weathered layer.
4. Errors of correlation.

The last three of the above-mentioned errors are limiting factors in accuracy of reflection seismograph work as at present carried out. With proper attention to the measurement of vertical velocities along the lines above indicated, and with such attention to weathered-layer corrections as economic aspects of the problem will usually permit, it is possible to reduce the errors from these sources to a point where the accuracy of the work meets substantially all requirements for commercial explorations.

When doing reflection work in areas characterized by a relatively few outstanding reflecting strata which are continuous over the entire area being explored, there will usually be little or no difficulty in correlating accurately for these strata, so that in such cases the danger of miscorrelation is virtually absent. When, however, reflecting strata are more or less vague and poorly defined, and particularly where discontinuities in the reflecting strata may occur due to a lensing out of formations or faulting, or where a number of reflecting strata exist fairly close together, there is always a possibility of miscorrelation from one set-up to another. Where such conditions exist, this source of error

can be greatly minimized by the use of more frequent reflection set-ups, and where conditions are extremely bad, continuous or overlapping set-ups are sometimes used. This increases the cost of the work, but it is sometimes the only way in which satisfactory accuracy can be assured.

In commercial oil explorations, in much of the Mid-Continent area in North America, depth determinations on the most important stratum, namely, the Viola Limestone, can now be made with a considerable degree of accuracy, the errors usually not exceeding 3 to 8 metres, particularly where wells are available for checking vertical velocity values. In wild-cat areas, where velocities have to be measured experimentally, errors may run from 5 to 20 metres. In ordinary operations, in areas such as the Texas–Louisiana Gulf Coast section, we are but secondarily concerned with absolute depths, but primarily with relative depths from point to point over potential structures. These relative depths can now be obtained with an accuracy of from 5 to 20 metres, except for occasional possible miscorrelations resulting from faults or lenticularities that may be but vaguely revealed by the seismograms.

Scope of Application of Reflection Seismograph

With the modern, perfected type of seismograph equipment it is safe to state that it is rare to meet conditions, in potential oil-bearing areas, where it is impossible to obtain information of considerable value in the search for oil deposits, Such information can be secured at a cost usually nominal compared with the cost of wild-catting by drilling without the benefit of prior seismograph work.

Conclusions

1. The accuracy of depth and dip determinations in reflection seismograph work may now be regarded as adequate to meet the requirements of commercial oil exploration.

2. The essentials of success in securing satisfactory reflection records embrace three conditions necessary for suppressing undesirable wave trends from the record. These three conditions are:

(*a*) Deep planting of shots to depths of 20 to 100 metres, or more.

(*b*) The use of short shooting distances relative to the depths of the reflecting horizon; these shooting distances usually being about 300 to 500 metres, when exploring strata below 500 metres in depth. For shallower strata shorter shooting distances will usually be necessary.

(*c*) The use of adequate filtration to eliminate from the records the waves outside of the 40 to 60 cycle band.

3. Electrical seismographs have shown marked superiority over mechanical seismographs, chiefly because of the more effective filtration which they make possible. Practically all commercial reflection shooting at the present is done by the electrical types of instruments.

4. The reflection method in its present state of development can now be used with commercially valuable results in nearly every type of geology of interest encountered in commercial oil exploration work.

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SECTION 9

METHODS OF DRILLING

PERCUSSION TOOL PRESSURE DRILLING

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As its name implies, the percussion-tool system of drilling utilizes the pounding action of a heavy cutting-tool to disintegrate the formation to be passed through. The system consists essentially of means whereby the drilling tool can be raised a short distance and then be allowed to fall by its own weight, until, coming into sudden contact with the bottom of the hole, the formation is shattered or drilled up. As drilling proceeds water is put into the well to form a liquid mud with the cuttings made which is bailed out as it becomes necessary.

Various mechanical means have been employed to transmit this necessary reciprocating motion to the drilling tools, and many methods have been used to form the connecting link between the actual drilling tool and the machinery at the surface of the ground.

The need for deeper wells and the inherent difficulties encountered while drilling through various kinds of rocks resulted in many improvements to the system. Ash poles gave way to the use of iron rods, a hoisting drum was used for handling the rods, a walking beam operated by a connecting rod attached to a crank provided the necessary lift to the drilling tools, and a steam engine supplied the necessary power.

Modifications of the pole-tool system of drilling were in use in the Russian and Galician fields until fairly recent years.

When drilling with iron poles, however, the weight of the total string in a deep well was considerable, and the continual reversal of strains from full load to zero which occurred on each stroke, about 30 times a minute, resulted in many breakages and consequent fishing jobs.

The time taken in handling the rods was also a serious factor in deep wells, since after each 'run' the tools had to be withdrawn from the well by unscrewing the rods one by one, the process being reversed before drilling could be resumed.

To overcome these very serious handicaps the American 'Standard' system was introduced; the most revolutionary change from the Canadian pole-tool system was the substitution of a manilla cable in place of the iron rods. With this flexible connexion from the surface plant to the drilling tools, the speed of withdrawal was accelerated considerably, and the number of strokes which could be delivered to the drilling tool was now limited only by the rate at which the tools could fall by gravity. A threaded feed attachment, the temper screw, was introduced for lowering the tools as drilling proceeded, and a separate drum for handling a bailing line became standard practice.

Although the substitution of a manilla cable for the solid rods was a marked improvement, other difficulties still presented themselves. The chief objections to a manilla cable were the tendency for excessive wear to take place, especially where the cable came in contact with the sharp edges of thin bands of hard rock, and also the fact that when drilling in a hole which contained a considerable amount of water the floating effect of the manilla retarded to some extent the free falling of the drilling tools.

These difficulties were eventually overcome by the introduction of a steel cable in place of the manilla rope, this latest improvement resulting in the present percussion system of drilling.

This method has been employed for wells over 9,000 ft. deep. It is not, however, recommended for depths exceeding about 4,500 ft., since the risks inseparable from this system are increased considerably in deeper wells.

In suitable formations which are free from caving difficulties and where troubles arising from water-shows are not likely to be encountered, the percussion system compares favourably with the rotary system on many points.

In 'wild-cat' drilling where water supplies are scarce and where fuel has to be transported for long distances, the percussion system has much in its favour, since the power required is considerably less than that required by the rotary system. The crew required to handle the plant is also smaller.

In test drilling for oil-bearing formations the advantages sometimes put forward in favour of the percussion system are:

(1) In view of the possibility of 'dry-hole' drilling, i.e. with only sufficient water in the well to enable the drilled debris to be formed into a thin mud, a much lower static pressure is exerted on the formation drilled through than is the case with the rotary system which necessitates the well being full of drilling fluid. The advantage in favour of the percussion system is that if oil- or gas-shows of low pressure are encountered they may be held back by the greater static pressure exerted by a long column of drilling mud and consequently might be passed unnoticed.
(2) The cost of equipment is less.
(3) The running costs are lower.

On the other hand, the modern rotary equipment is capable of drilling to greater depths and is able to cope with formations which the percussion system could not penetrate. In formations which are inclined to cave badly and where the presence of high-pressure water-shows would retard progress with percussion tools, the rotary system is undoubtedly the better.

A modern percussion drilling plant consists essentially of:

(1) Derrick.
(2) Rig.
(3) Power unit.
(4) Drilling tools and accessories.
(5) Casing and accessories.

The weight of these vary according to the depth of well and the formation to be drilled through. The gear varies from light portable outfits capable of drilling from 300 to 1,000 ft. to a full-sized plant designed to drill to 9,000 ft.

The former can be obtained mounted on motor lorries complete with their own power unit, an outfit capable of drilling a 6-in. hole to 600 ft. weighing about 7½ tons.

An outfit capable of drilling to 5,000 ft. complete with necessary tools and casing weighs between 350 and 400 tons.

Derrick.

The derrick may be of either wooden or steel construction. In view of its higher salvage value and the fact that it may be erected and dismantled any number of times, the steel derricks have to a large extent replaced those of wooden construction.

For deep drilling the derrick is usually 80 ft. high, tapering from a base 20 ft. square to an opening at the top 5 ft. 6 in. square. The load-carrying capacity to which the derrick will be stressed depends almost entirely on the amount of casing to be handled by the derrick. In a well 5,000 ft. deep the weight of the heaviest string of casing would probably be about 60 tons; to this weight, however, a margin must be allowed to cover conditions which arise due to cavings around the casing and other factors which tend to 'freeze' the casing. A type of derrick generally used for deep percussion drilling is designed to carry a load of 60 to 100 tons.

The derrick is surmounted by a crown block. This carries a series of sheaves over which the casing block lines are reeved and also other sheaves which carry the drilling line and the sand line.

Near the base of the derrick, placed on opposite sides and running on suitable bearings, the bull wheel and calf wheel are housed. The former consists of a steel drum of sufficient capacity to take the full length of drilling cable. At one end a tug rim is arranged for receiving the drive through a $2\frac{1}{2}$ in. dia. manilla rope, while at the opposite end a brake rim is attached.

The calf wheel is of similar construction, except that the line capacity is sufficient only to house the amount of line required for the reeving of the casing blocks which in the case of an 80-ft. derrick may be about 1,000 ft. The calf-wheel drive is by flat link chain and sprocket.

Rig.

The rig consists of a framework generally of steel construction arranged to carry:

(1) Band-wheel shaft.
(2) Sand reel.
(3) Sampson post.
(4) Walking beam.

The band-wheel shaft of a medium-weight outfit consists of a steel shaft 6 in. dia. by 9 ft. $3\frac{1}{2}$ in. long. It runs on suitable bearings and carries the crank arm, the band wheel with tug rim for operating the bull wheel, chain sprocket for the calf-wheel drive, chain sprocket for sand-reel drive, and is sometimes fitted at the end opposite the crank arm with a cat-head.

The band wheel is usually of steel construction 11 ft. dia. with a 13-in. face for a 12-in. wide driving belt. On one side of the band wheel the tug rim is attached: it consists of a steel casting about 6 ft. dia. suitably grooved to take a $2\frac{3}{4}$-in. dia. manilla rope. This rope drive transmits the power from the band-wheel shaft to the bull wheel which is placed on the opposite side of the derrick. For deep wells the tug rim is arranged to take two driving ropes.

In order to provide the correct stroke of the drilling tools the crank arm is provided with three or four wrist-pin holes into either of which the crank pin can be inserted. The length of stroke obtainable ranges from 2 ft. 11 in. to 4 ft. 6 in., the stroke required depending on the depth of the well, the formation to be drilled through, and the amount of water standing in the well.

The sand-reel and calf-wheel sprockets are fitted with dog clutches to enable them to be disengaged while drilling is proceeding. They are mounted at suitable positions on the band-wheel shaft and transmit, through flat link chains, the drive to the sand reel and calf wheel respectively.

The sand reel on which the bailing line is spooled is placed at the back of the band wheel. It runs in suitable bearings and is driven by the chain from the sprocket on the band wheel. The latest models are fitted with a friction clutch which can be disengaged while the bailer is being run into the well, and provides the necessary quick pick up of the bailer which is a great advantage in cleaning out the drilled debris.

At a point just outside the derrick legs the sampson post is attached to the rig foundation members. It consists of a rigid vertical steel post 15 ft. 6 in. or 17 ft. high, on top of which are two bearings in which the shaft of the walking beam is housed. The walking beam consists of a steel beam of suitable section mounted at about its centre position on a fulcrum bearing. To one end a pitman—or connecting rod—is attached, forming a connexion between the outer end of the walking beam and the crank arm on the band-wheel shaft. At the opposite end and exactly over the mouth of the well a temper screw is attached, to which the drilling line is coupled when drilling is actually in progress.

Types of Power.

Steam is undoubtedly the most flexible and convenient form of power, and where conditions are such that good water is available with a cheap supply of fuel this form of power is usually preferred. Many wells of considerable depth have, however, been drilled by cable tools using internal-combustion engines and also by electrical power.

With steam power a single-cylinder 12×12-in. engine using steam at about 120 lb. per sq. in. is considered ample for deep cable-tool wells, while for shallow wells a correspondingly smaller engine can be employed.

Engine.

In view of the varying conditions of load which are imposed on it, the engine is usually of special design. It must be of rugged construction, yet light and capable of responding rapidly to frequent changes of speed. Owing to the peculiar nature of the load while actually drilling, which varies from full load while the drilling tools are on the upstroke to a 'minus load' when they are falling by gravity, it is important that the inertia in the flywheel shall be low. With a heavy flywheel tending to even out any changes of load the necessary free falling action of the drilling is retarded, thereby decreasing the effective blow and the consequent shattering action of the drilling bit on the formation being penetrated. For this reason drilling engines are usually provided with a light flywheel, to the rim of which additional rims can be bolted as the depth of the well increases.

Accurate speed adjustment is essential in order that the motion of the drilling tools can be controlled to suit drilling conditions. This is determined by the rate at which the drilling tools can fall, this rate being again influenced by several factors such as the amount of fluid in the well, the size of the drilling tools in relation to the size of the hole being drilled, the straightness of the well, and the amount of drilled-up debris through which the tools must

fall. The ideal motion, and one which must be very closely approximated if efficient progress is to be made, is that which allows the drilling tools to strike 'bottom' the instant before the upstroke of the walking beam begins, although because of the elasticity in the cable it is probable that the beam is already returning on the upstroke as the tools strike. This motion ensures the maximum weight of the blow on 'bottom' and relieves the gear of the shock load which occurs if the upstroke of the beam takes place before the drilling tools have completed their downstroke. As the depth of the well increases the amount of stretch or elasticity in the drilling cable plays an important part and affects materially the amount of travel actually imparted to the drilling tools.

In view of these features, which are probably peculiar to drilling, the engine is controlled entirely on the throttle valve. This is done by means of an endless wire line on a hand wheel fixed at the driller's position on the derrick, no governors of any kind being fitted.

The crank shaft is fitted with a crowned belt pulley usually 24 in. dia., and of sufficient width to carry a 12-in. wide belt. This provides the power transmission from the drilling engine to the band wheel of the drilling rig.

Boilers.

The type generally favoured is the fire-tube locomotive type. The capacity depends on the weight of gear to be handled and the depth of the well to be drilled. For wells of 5,000 ft. boiler capacity of 5,000 lb. of steam per hour is sufficient for maximum demands. The number of boilers to be installed to provide this steam output is largely a matter of choice or circumstances, and is often governed by transport conditions, quality of feed water, and the time factor in completing the well. Two boilers each of 2,500 lb. per hour steaming capacity provides a useful and fairly flexible arrangement, which has the advantage of allowing one boiler off for cleaning while allowing drilling to proceed, admittedly not efficiently, with the second boiler.

Drilling Tools.

The number and variety of these can only be determined from a study of the conditions likely to be encountered while drilling. In isolated districts far away from sources of supply it is essential that considerable quantities of spares be carried if the work is to proceed expeditiously. The formations to be drilled through, the existence of underground water which must be cased off, the liability of the strata to caving trouble, and the degree of hardness of the various beds to be penetrated all influence the question as to which tools are or are not necessary for the successful completion of a deep cable-tool drilled well.

The type of tools which are considered essential also vary according to the views of different operators and the practice usually employed by them. Only those which are generally considered essential will be dealt with here.

A 'string' of cable drilling tools consists of:

(1) 1 rope swivel (Fig. 1).
(2) 1 set of jars (Fig. 2).
(3) 1 sinker bar (Fig. 3).
(4) 1 drilling bit (Fig. 4).

These are coupled together in the order named by tapered threaded joints. The weight and size of the 'string' depends on the size of hole being drilled; for a bit diameter of 15 in., 4×5-in. joints would be used, while for a hole of 6 in. dia. $1\frac{5}{8} \times 2\frac{5}{8}$-in. joints would be normal practice. Except in the larger sizes, the controlling factor as regards the size of 'string' to be used is the inside diameter of the casing through which it will be used. There must be sufficient space between the tools and the inside of the casing to allow the former to fall freely and also allow room for 'fishing' tools to be run in case of necessity.

Casing.

The casing programme again depends on the depth of the well, the underground waters which must be cased off, caving formations, and the pressures likely to be encountered when oil or gas is encountered.

A list of some combinations of casing weights and diameters which have been adopted by the American Petroleum Institution is as follows:

1		*2*		*3*	
Size, in.	*Weight per ft., lb.*	*Size, in.*	*Weight per ft., lb.*	*Size, in.*	*Weight per ft., lb.*
$13\frac{3}{8}$	60	$13\frac{3}{8}$	48	13	50
$10\frac{3}{4}$	45·5	$10\frac{3}{4}$	40·5	$10\frac{3}{4}$	40·5
$8\frac{5}{8}$	32	$8\frac{5}{8}$	28	$8\frac{5}{8}$	28
7	24	7	20	7	20
$5\frac{1}{2}$	20	$5\frac{1}{2}$	17	$5\frac{1}{2}$	17
$2\frac{1}{2}$	6 5	3	9·3	$2\frac{1}{2}$	6·5

Fishing Tools.

In spite of the efforts which have been made in recent years to introduce special steels and fine limits of accuracy in manufacture with a view to minimizing the number of breakages which occur in cable drilling tools, these breakages are still very frequent. Fishing jobs constitute one of the bugbears of this system, and many wells are lost owing to the breakage of the drilling tools.

Some fishing jobs prove to be comparatively simple, the lost tool being recovered in the course of an hour or so, while others, due to complications such as a bit breaking off and falling over into the wall of the hole, may take months to recover and in some cases lead to the abandonment of the well.

The cable-tool system does not lend itself to fishing, since in most operations the fishing tool is suspended on a steel cable which provides no positive means of manipulation of the fishing tool in relation to the position of the tool to be recovered. A considerable amount of ingenuity has been displayed in the design of fishing tools, but it is often necessary to design tools specially for some particularly difficult jobs. The normal set of fishing tools generally comprises the following:

(1) Rope spear (Fig. 5).
(2) Half-turn sockets.
(3) Slip sockets (Fig. 6).
(4) Rope knife (Fig. 7).
(5) Horn sockets.
(6) Spuds.

In commencing a well, a cellar approximately 5 ft. deep by 6×6 ft. is usually excavated and lined with concrete, a hole of the diameter of the drilling bit being formed in the centre of the cellar floor. The tools are then 'strung up', but since the drilling 'string' may be anything from 30 to 40 ft. in length, while the height of the walking beam is only about 15 ft. above the cellar floor, the beam cannot be used until sufficient hole has been drilled to accommo-

Fig. 1

Fig. 2

Fig. 3

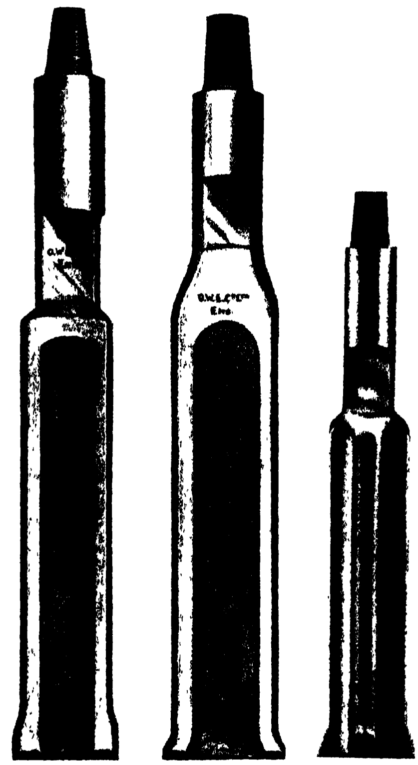

Fig. 4

Fig. 5

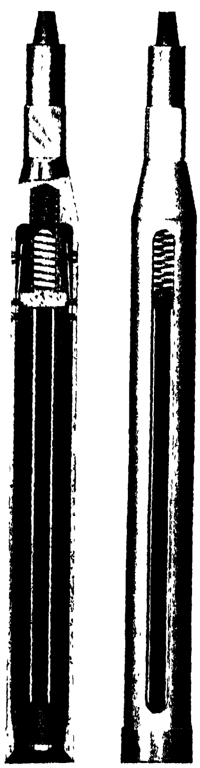

Fig. 6

Fig. 7

Fig. 8

Fig. 9

date the 'string' of drilling tools. To overcome this difficulty the well is usually 'spudded' in for a depth of 100 to 200 ft.

This 'spudding' action is obtained by attaching one end of a jerker line to the wrist pin of the crank on the main rig shaft, while the other end is coupled to a spudding shoe which is placed behind the drilling cable. The bull-wheel brake is applied to prevent rotation of the bull wheel. The rotation of the crank thus imparts a reciprocating motion to the jerker line which, by pulling on the drill line at a position between the bull wheel and the crown block, raises and allows the drilling tools to fall. As the tools penetrate the formation, line is paid out from the bull wheel at a rate which allows the drilling bit to just strike bottom at each stroke.

This 'spudding' operation is at the best an unsatisfactory method of drilling, and as soon as sufficient hole has been made to accommodate the drilling tools and the necessary amount of drilling line to provide some measure of elasticity, normal drilling off the walking beam is instituted.

Drilling can then proceed until conditions are such that casing must be inserted, possibly to hold back cavings or to shut off a water-show, both of which may retard, if not prevent, the progress of the work.

With a string of casing inserted but still being 'carried' it becomes necessary to drill with a bit that will pass through the casing a hole sufficiently large for the casing to pass through. This is accomplished in either of two ways. A 'straight' bit may be used which will drill a hole the same size as the inside diameter of the casing, this hole afterwards being enlarged by means of an under-reamer (Fig. 8). Another method is to use an eccentric bit (Fig. 9). The construction of the latter type is such that although it will pass through the casing, its eccentric form enables it to cut a hole considerably larger than its own diameter.

In suitable formations eccentric-bit drilling is often satisfactory and is used extensively by those who have been trained in certain schools; in the United States of America, however, the straight bits and under-reamers are preferred.

When the point is reached at which the first string of casing is to be landed, a seat is prepared on to which it can be lowered, all caving formations and water-shows thus being sealed off at this point.

In many cases, owing to the corrosive effect on the casing of underground water, the practice of cementing the casing is becoming almost universal. This is effected by raising the casing a few feet off its seat and pumping down through the casing—or a special string of tubing inserted for the purpose—a cement slurry. The quantity required to fill the annular space between the outside of the casing and the bore of the well depends on the amount of caving that has occurred and the height to which it is desired to place the cement.

The cement slurry is mixed at the surface to a slurry of from 1·6 to 1·8 specific gravity, and is then pumped into the casing, followed by pumping in a quantity of water sufficient to raise the cement to the required height outside the casing. The casing is then lowered on to its seat and drilling operations are suspended for sufficient time to allow the cement to set. This time varies from 3 to 10 days.

After the cement which remained inside the casing has been drilled out, casing tests are usually made. This may consist of filling the well with water and applying an additional pressure by means of a pump. This pressure is a purely arbitrary one, and 500 lb. per sq. in. is generally recognized as constituting a fair and reasonable test of the cementing job. Another test consists of bailing out the water from the inside of the casing, thereby creating a differential pressure between the inside and the outside, any rise of water inside the casing indicating a leak into the well. For the latter test accurate information regarding the level of underground water should be available, since in deep wells the difference between the levels of the water inside and outside the casing may result in its collapse due to too great a differential pressure being created.

The same procedure as regards drilling and running casing is carried out until the objective is reached, in the case of an oil-well usually a cap-rock below which oil is expected.

The method employed from this stage depends on the amount of oil or gas likely to be encountered, and upon the pressure condition under which it may be found. For wells of low pressure in which the oil when tapped will not rise to the surface, no special precautions are necessary. The well is usually cleaned out thoroughly, probably bailed in order to obtain some idea of its productive capacity, and then put 'on the pump'. Where high-pressure conditions are expected and in areas where conditions are unknown, other precautions, however, must be taken before drilling into the oil- or gas-bearing formations.

With the last string of casing set and cemented the well-head is prepared for 'drilling-in'. A main valve usually of the gate type is flanged or threaded to the well casing and above this the 'Christmas Tree' is attached. The latter consists of a head fitted with side outlets to which valves are attached, the main bore being at least of the same bore as the main valve and the casing. The well is then filled with water, the side valves and the upper end of the 'Christmas Tree' are closed, and the whole well is subjected to a pressure in excess of that which is likely to be exerted by the pressure of the oil or gas when drilled into. Since at this stage this pressure factor is unknown, the only means of ensuring safety is to employ the heaviest fittings and to test them to a pressure higher than that which could reasonably be expected when the well is completed. For present-day high-pressure wells, valves and well-head fittings are often tested to 6,000 lb. per sq. in.

After the well-head fittings have been tested the cement is drilled out and a further test applied to ensure that the casing-shoe seat and the cementing job are satisfactory.

Pressure Drilling.

The safest method so far employed for 'drilling-in' wells with the cable tools is that known as the container method (Fig. 10). For this a container is made up of two lengths of casing preferably of the same size as that which is to be drilled through. This container is fitted at the lower end with a flange by which it is attached to another gate valve placed above the 'Christmas Tree'. At the upper end another flange is fitted to which is attached a polished-rod gland. Working through this polished-rod gland is a polished rod which consists of a tube of heavy construction of sufficient bore to allow the drilling cable to pass freely through, and with an outside diameter of about 1¾ in. and a length of 10 ft. On the lower end a retaining collar is threaded, while at the upper end a polished-rod head is attached.

The polished-rod head consists of a housing into which rubber pads are fitted, the inner faces of which are grooved to receive the drilling cable. Immediately below these

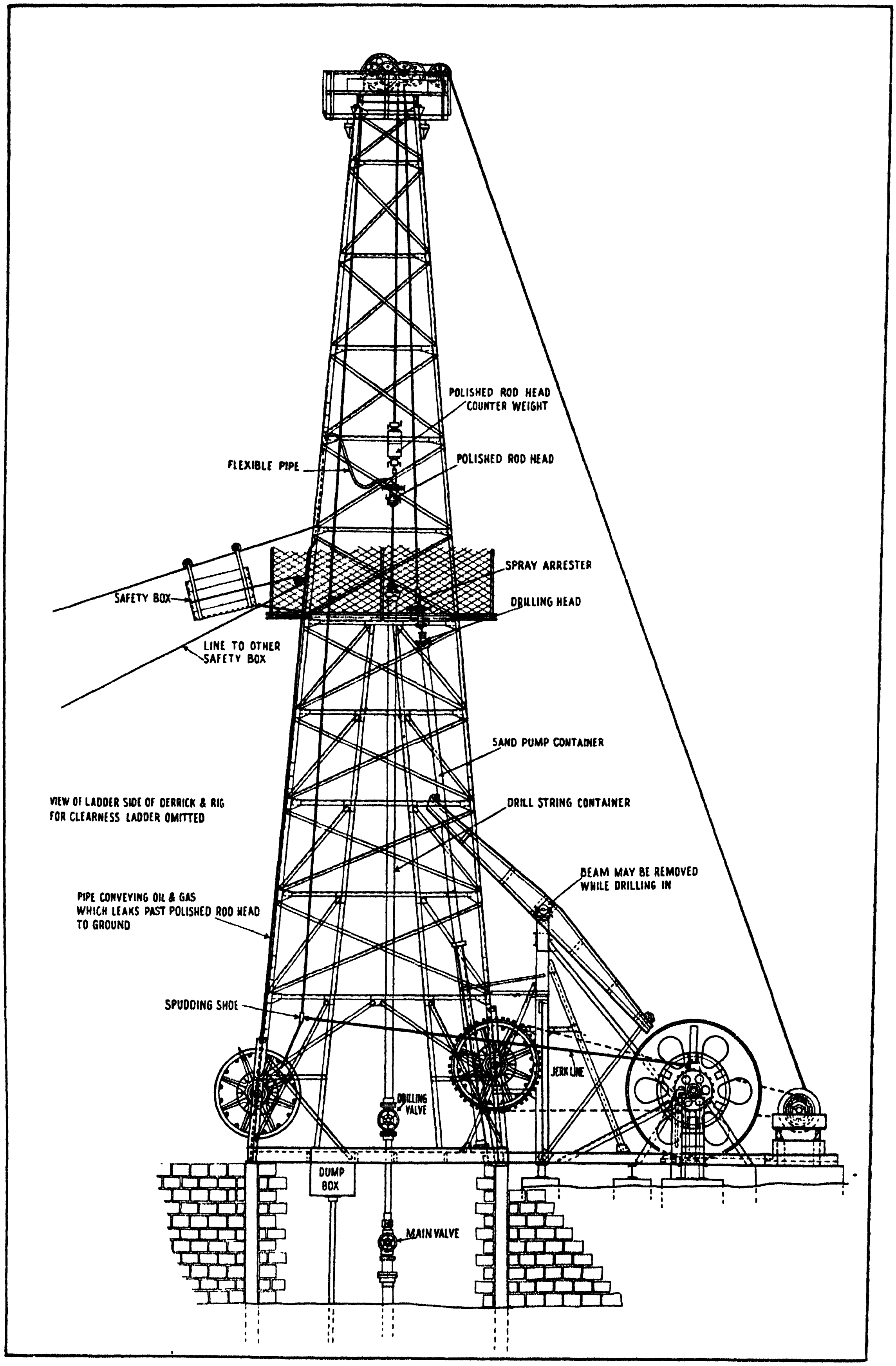
POLISHED ROD HEAD
COUNTER WEIGHT
FLEXIBLE PIPE
POLISHED ROD HEAD
SPRAY ARRESTER
SAFETY BOX
DRILLING HEAD
LINE TO OTHER SAFETY BOX
SAND PUMP CONTAINER
VIEW OF LADDER SIDE OF DERRICK & RIG FOR CLEARNESS LADDER OMITTED
DRILL STRING CONTAINER
BEAM MAY BE REMOVED WHILE DRILLING IN
PIPE CONVEYING OIL & GAS WHICH LEAKS PAST POLISHED ROD HEAD TO GROUND
SPUDDING SHOE
JERK LINE
DRILLING VALVE
DUMP BOX
MAIN VALVE

FIG. 10.

rubber pads two steel gripping pads are fixed, these also being provided with grooves which correspond to the diameter of the drilling cable. Both the gripping pads and the rubber pads are so arranged that they can be forced into contact with the drilling cable by means of threaded spindles suitably packed through glands to prevent leakage. Above the polished-rod head and attached to it is a spray arrester. This takes the form of a tee piece with a flanged connexion on the side outlet and a gland at its upper end through which the drill line can pass. A packing gland is fitted at the upper end by means of which a soft grade of packing can be held in contact with the drill cable. From the side outlet a flexible hose of about 2 in. dia. is led to lengths of 2-in. rigid pipe which are fixed in the corner of the derrick. By this arrangement any oil which leaks past the polished-rod head is led through the 2-in. pipe into a small tank placed on the ground, preferably some distance from the derrick. In pulling the tools from a well 3,000 ft. deep under a pressure of 800 lb. per sq. in., about 200 gal. of oil escapes into this tank.

Since with this method a container about 40 ft. long must be used, the walking beam cannot be employed to impart the drilling motion to the tools; it is therefore necessary to drill by spudding. This spudding action is obtained in the same manner as when commencing the well.

After a final test of all the well-head fittings, the drilling tools are connected up, with the drilling cable passing through the polished rod and its fittings, the tools being placed inside the container. This complete assembly is then placed in a vertical position and bolted above the upper gate valve. The gland of the spray arrester is then tightened snugly around the drill cable, the gate valves opened, and the drilling tools lowered to the bottom of the well in the usual manner.

The spudding line is attached to the drill line where the latter leaves the bull wheel, and the polished rod is adjusted and clamped to the drill line in such a position as to allow its maximum downward travel as drilling proceeds.

With a 10-ft. polished rod and assuming a spudding stroke of 2 ft. 6 in. about 7 ft. of drilling can be done before making further adjustment to the polished rod to prevent its upper end coming into contact with the polished-rod gland.

Drilling is continued in this manner until the tools must be withdrawn from the well, when the same operations, as used when running in, are carried out, but in reverse order.

This method of 'drilling-in' under pressure is quite satisfactory up to well-head pressures of 800 lb. per sq. in., but at pressures higher than this, oil and gas find their way into the core of the drilling cable and passing up through the polished-rod head escape to atmosphere some distance above it.

When drilling against well pressures of between 500 and 800 lb. per sq. in. the well pressure, acting on the under side of the polished rod, tends to retard the free falling action of the tools. This is particularly noticeable when using a string of small tools as in drilling, for instance, a 6-in hole. The effect can, however, be balanced by the use of suitable weights attached around the drilling line above the spray arrester.

In wells which produce oil under sufficient pressure to enable them to flow, the debris can be removed by this flow as drilling proceeds, the oil being led from the side lines in the flowhead to suitable settling and storage tanks. In cases, however, in which the well will not flow, the debris must be removed by a bailer in the usual manner; the bailer must be run through a container and fittings in exactly the same way as the drilling tools.

The extent to which safely precautions are taken will be governed by the mining laws of the country in which drilling is being carried out, or by the degree of risk an operator can or is prepared to take. In any case, the following safety measures should be instituted:

(1) Boilers should be placed as far as practically possible from the well and in the direction from which the prevailing wind blows. They should be fitted with steam snuffers for effectively putting out the boiler fires.
(2) Long-distance controls should be fitted to all valves on the well head.
(3) A safety line should be fitted from the platform to the ground.
(4) Band brakes should be sprayed with water.
(5) Bronze headed hammers should be used.
(6) Gas masks should be available and the crew trained in their use.
(7) If work is carried out during the night—it should be avoided if possible—electric lighting should be arranged by flood lighting from the ground outside the derrick.
(8) Operating levers should, where possible, be extended outside the derrick.
(9) Smoking should be prohibited, and no matches allowed on the job.
(10) Safety belts should be provided for men working on the platform.
(11) The derrick floor and the ground around should be kept clear of obstruction, clean, and free from oil.

PRESENT TRENDS IN ROTARY WELL DRILLING AND COMPLETION

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School of Petroleum Engineering, University of Oklahoma, U.S.A.

Introduction

WHEN rotary drilling equipment was first used for drilling oil-wells at the beginning of the century, these first wells were drilled to a depth of only 800 ft. The formations drilled by this early rotary equipment were sufficiently soft to permit their being drilled by hard steel fish-tail bits, the only type of rotary bits then available.

The demand upon rotary drilling equipment and technique has not increased at a uniform rate since its introduction, neither has this increased demand always been met promptly with better materials, better equipment, and better technique. Usually some enterprising company or individual set a depth record ostensibly beyond the capacity of the equipment credited with the performance. Then for a period of several years there ensued widespread drilling to these new depths with equipment which was not altogether adequate. During this interval it was generally believed that rotary drilling had proceeded to its ultimate attainable depths. Better materials and new inventions caught up with the demand, only to have a new depth record established with this new equipment. In this fashion rotary drilling proceeded to greater depths with ever-increasing demands upon materials and technique.

Five years ago many difficulties were anticipated where the depth drilled exceeded 5,000 ft. To-day many wells are being drilled below 8,000 ft., and these deep wells are being drilled in about one-third the time consumed in drilling wells to similar depths 5 years ago. Thirteen wells have been drilled below 10,000 ft. with a depth record of 12,786 ft. This latter achievement was remarkable in that no particular difficulties were reported in the lower portion of the well.

Those who are responsible for anticipating the future demands upon deep well drilling equipment are confident that it is possible to develop materials which will absorb the stresses imposed where wells are drilled to a depth of 15,000 ft.

The major problems which have arisen in connexion with rotary drilling will be presented and the manner in which these problems have been overcome, or at least rendered tolerable, will be discussed. Present trends in rotary drilling will be considered under the following headings:

1. Improvement in materials entering into the construction of rotary equipment.
2. Rotary equipment design.
3. Securing drilling tool efficiency.
4. Improved casing practices.
5. New developments in cementing casing.
6. Control of rotary drilling mud.
7. Application of controlled directional drilling.
8. Combating heaving shales in rotary drilled wells.
9. Pressure drilling and well completion.
10. Dismantling, transporting, and rigging up.
11. Selection of the proper type of rotary equipment.
12. Completion of rotary drilled wells.

Introduction and Growth of Rotary Equipment Use

The first rotary drilling equipment is reported to have been developed by M. C. and C. E. Baker, water-well drilling contractors of South Dakota [4, 1934]. In drilling wells the Baker brothers used what they termed the 'jetty' system, wherein water was poured into the annular space and allowed to escape upwards through the hole in the bit and through the hollow drill stem. The drill stem was equipped with a series of valves designed to hold the mud as it escaped upwards. As the well was deepened this

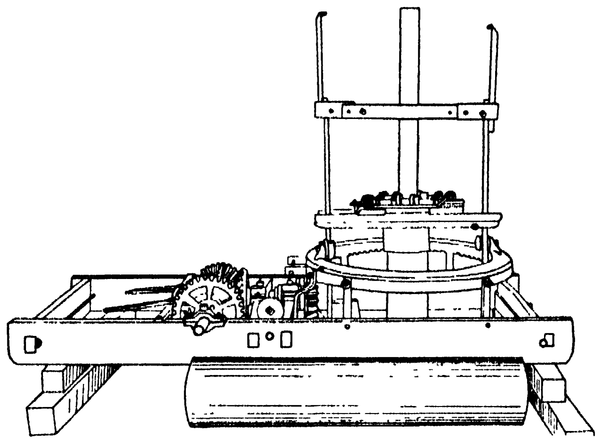


FIG. 1.

method failed to work because the mud would not rise freely in the stem. Next the course of the water was reversed and the water introduced through the drill stem. The water was first poured into the upper end of the hollow drill stem, but later was forced through the drill stem and the hole in the bit, using the force of gravity supplied by an adjacent water-well.

The drill stem, which consisted of small-diameter pipe, was at first turned by hand. Later a skid-mounted rig was designed to stabilize the upper end of the drill stem, and a set of pipe grips was designed and made to rotate the pipe. A sweep powered by horses furnished the power for rotating the pipe. The upper end of the drill stem was held in a vertical position by short lengths of casing at the mouth of the drill hole. Bevel gears were provided, by means of which the drill stem could be rotated in either direction.

This crude rotary outfit was brought to Corsicana in 1895. In it the American Well and Prospecting Company saw the possibilities offered by the rotary method for drilling the soft shales of the area. This company set to work to develop the rotary, and as a result came the first rotary which drilled the Captain Lucas well in the Spindletop field in 1901. Fig. 1 is a reproduction of the rotary used with this rig.

The improvement in rotary equipment since this first crude rig, and the natural advantages of rotary drilling for

present deep wells and high formation pressures, are responsible for the use of rotary equipment at more than 10,000 wells each year.

Improvement in Materials Entering into the Construction of Rotary Equipment

Materials used on these early rotary rigs would have included: malleable chain; cast-iron sprockets, sheaves, rotaries, and pumps; low-carbon lap-weld drill pipe used without tool joints. In the soft shale areas, where rotary drilling had its beginning and where the wells were shallow, the above materials were fairly satisfactory—at least with such equipment it was possible to drill oil-wells more rapidly than was possible by the standard tool method.

As wells were drilled to greater depths it became necessary to improve the quality of the materials. Heat treating was used to care for the needed improvement of early steel. For a time this sufficed, but in recent years heat treating alone has proved inadequate. Next high-carbon steels were introduced, and a more careful control was observed in processing and heat treating. The depth to which wells were being drilled increased, and it was necessary further to improve the quality of the material which entered into the construction of these rotaries designed for greater depths. At the present time many alloy steels are being used to meet the ever-increasing demand for greater strength of materials. Hard surface materials are being applied to the cutting edge of tools.

The extent to which materials have been improved can best be portrayed by the fact that certain well casing has been developed to the point where it could be set at approximately 15,000 ft., with a safety factor of 2, provided the joints were as strong as the body of the casing.

Even with these marked improvements in quality of material, the task of the manufacturer is not yet completed. Within the next few years the depth record for oil-wells will very likely be extended 2,000 or 3,000 ft. Another reason is that the industry is just emerging from a period when rotary equipment, particularly equipment at the surface, has been strengthened by the simple expedient of adding more metal. The recent depression has demanded cheaper per foot cost for drilling. Contractors have been forced to consider design and quality of material if for no other reason than increased portability.

Determining the Worth of Metal [5, 1929]. Four quantities are ordinarily used in describing the physical properties of metal. These are, ultimate strength, elastic strength, ductility, and reduction of area, values which are measured quantitatively by testing to destruction a sample of the metal in question.

The ultimate and elastic strengths are a measure of the ability of this metal to carry a load, while the elongation and reduction of area indicate the extent to which the metal in question can deform under load without fracture. This latter property is equally as important as the former, since design considerations will seldom permit one to forget the notch effect of threads, shoulders, and keyways. If the metal is plastic—that is, if it will permit a high degree of deformation—these stress concentrations will be redistributed over a larger area of metal. The manufacturers of metallic materials must therefore consider both strength and plasticity, with a view to securing a correct balance of the two properties to best meet the particular demands upon the material under consideration.

Heat Treatment. With the exception of the carbonizing and nitriding processes, heat treatment properly carried out does not alter the chemical composition of steel. Heat treatment affects the physical form of the elements in steel. If a specimen is raised to exactly the proper temperature and then cooled rapidly, the strength and hardness of this sample can be increased in a surprising manner, the effect being more noticeable with alloy steels than with plain carbon steels. However, as the strength of the metal is increased the plastic properties are decreased, and if care is not observed, stress concentration may offset the gain in strength. Since the outside of the metal in question must be cooled first, the outer layers shrink before the inner portions cool. This sets up internal stresses due simply to volume changes. However, if the processing is skilfully handled, actual cracking of the metal during this sudden cooling may be avoided. If the treatment has progressed thus far without producing actual fractures in the material, the metal in question may be heated slowly to a moderate temperature to relieve the inherent stresses produced in the hardening processes. In this way heat treatment furnishes a method for adjusting the relation of strength to plasticity, in accordance with estimated or service requirements.

Proper Adjustment of the Fundamental Qualities of Metal. Assuming for the present that the processors of metals have been able to produce materials of sufficient strength to meet the strenuous demands for present deep drilling, there yet remains the proper application of these qualities to secure for the various parts of the drilling equipment a satisfactory service record which is the ultimate test of the value of metal.

The problem of adjusting these fundamental relationships is extremely involved because the relationship cannot be reduced to a mathematical statement, and field-service records very frequently indicate that the experience and estimates of the manufacturer have not been adequate to produce materials which will withstand the variations of loading. Perhaps one or two illustrations will clarify this point. Suppose that a certain type of tool-joint fails through excessive wear or galling of threads. It can be safely concluded that if a harder and tougher material is used, galling and abrasion will be reduced. However, in producing a harder, tougher metal, the processing, if carried to extremes, may sacrifice plasticity, with the result that failure now occurs because of the tendency of the tool-joint to split. This demands a nicety of judgement to determine just how much plasticity can be sacrificed safely in order to produce increased hardness and toughness, and yet avoid the alternative of splitting tool-joints.

Recent estimates place the known reserves of oil within the United States at 12 billion barrels. These reserves are being exhausted at the rate of nearly 1 billion barrels per year [2, 1935]. It follows naturally that the oil industry will within the next few years explore many of the deeper zones which geologists may point out as likely oil-bearing sands. If this search to greater depths is to be carried out successfully, manufacturers of well-drilling equipment must produce even better material (probably better alloys) with almost unerring judgement of the fundamental qualities of metal to provide for the particular load imposed upon each member of the rig.

Present-day Trends in Rotary Equipment Design

Two major factors are operating to produce definite changes in rotary drilling equipment design. The first of these is the ever-increasing depth to which wells are being

drilled. This factor tends to stimulate research to discover methods of increasing the capacity of surface and subsurface equipment and materials. The other major factor is a demand, or rather a necessity, for drastically decreased per footage drilling costs. This second factor became important largely as the result of the recent depression within the oil industry.

Sometimes these two factors operate jointly to produce a new piece of equipment; at other times these factors are directly opposed and hence lead to some confusion on the part of the manufacturer.

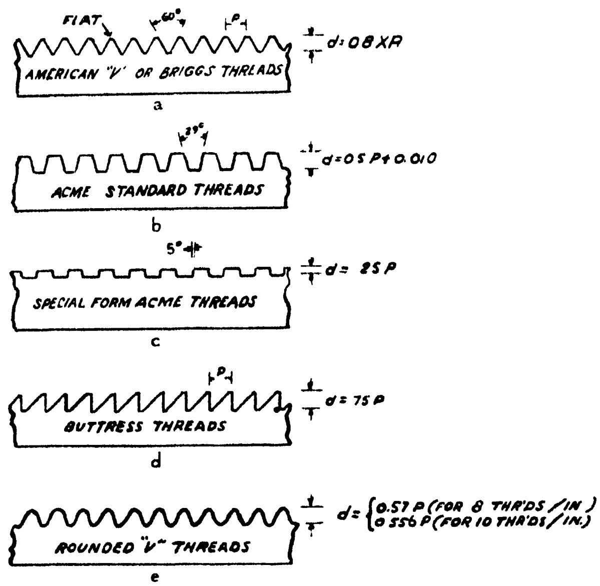


FIG. 2.

Improvement in material has been discussed; it is now fitting to trace the development of rig parts and supplies from what they were a few years ago to what they are at present. It would be interesting to follow the development of each piece of equipment, both surface and subsurface, which enters into the drilling and completion of a well, but space permits the treatment of only a few major items.

Increased drill-pipe capacity is more important than any other item because the ability of the drill pipe to withstand all variations of loading and stresses is the ultimate limiting factor which determines the depth to which wells may be drilled by the rotary method. For convenience increased drill-pipe capacity has been treated in another section.

Casing [7, 15]. Previous to 1923 all casing was furnace-welded from soft, low-carbon wrought iron or steel, the proportion of the former decreasing rapidly with improvement in the manufacture of steel.

Increased tensile and collapsing stresses imposed by the greater depths to which continuous casing strings are now being run have been met with improved quality of steel and the improvement secured through the production of a seamless upset casing.

The technique of running and cementing casing has, of course, contributed materially to reducing the required factor of safety below that of former years.

Fig. 2 at *a* shows the American V or Briggs thread commonly used for casing. The included angle between threads is 60° and the depth of the thread is 0·8 times the pitch. This thread possesses the disadvantage that it exerts a collapsing pressure upon the end of the pipe when the pipe is subjected to tension. It possesses the further objectionable feature that the greater thread depth results in the removal of more material in the process of threading and consequently reduces the area of metal under the root of the first perfect thread, and the strength of any threaded joint is dependent upon the area of the metal at this point. The other thread types shown in Fig. 2 have been developed for the purpose of avoiding the objectionable features of the Briggs thread. They have reduced the ratio of depth to pitch and have reduced the included angle in order to overcome collapsing stresses induced by tension. The

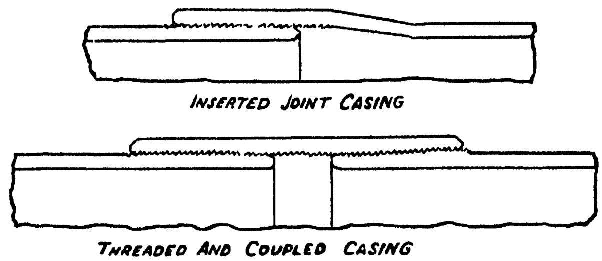


FIG. 3.

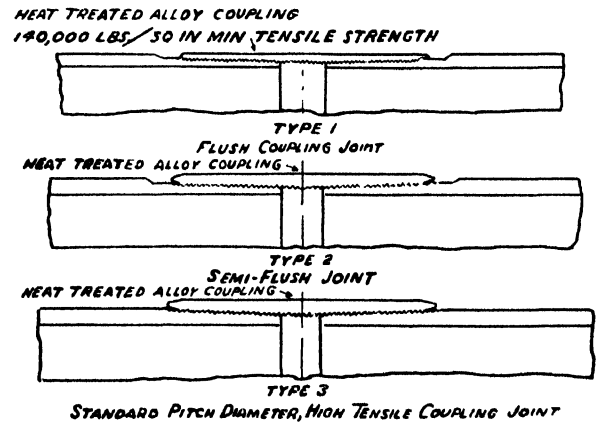


FIG. 4.

Briggs thread, however, continues to be favoured, especially if long threads and couplings are used. This is because any damage to threads may be repaired at the average machine shop and because the Briggs thread when properly made up furnishes a high-pressure seal without resorting to packing devices.

Inserted joint casing has been developed (Fig. 3) which is generally believed to give greater clearance with less reduction of strength than threaded and coupled joints. However, for equivalent areas under the threads the outside diameter through the expanded portion is the same as the outside diameter through the coupling.

Flush joint and semi-flush joint casing (Fig. 4) have been developed for special purposes where clearance is of more importance than joint strength. This casing serves a real need for pressure drilling, for running casing under pressure, for drilling through heaving shale, or for using as the lower portion of a combination string. It is erroneous, however, to represent that the joint strength is equal to that of threaded and coupled pipe or that joint efficiency approaches 100%. It is possible that the joint strength might be raised to that of threaded and coupled pipe by making use of heat-treated alloy steel. Even so the joint efficiency would not have been raised, and the cost of such heat-treated alloy steel would be several times as great as

the milder steel of equivalent joint strength making use of threaded and coupled casing. It is conceivable that this expense could be reduced by welding a short section of alloy steel to each end of the pipe-joint, slightly upsetting in the region of the weld (Fig. 5). The practicability of its manufacture is now in the process of proving.

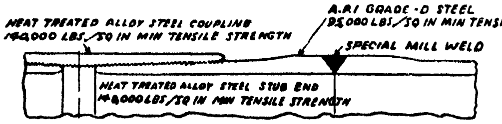


FIG. 5.

A recent improvement in coupled casing makes use of a thin heat-treated alloy-steel coupling of 140,000 lb. per sq. in. tensile strength to be used with upset casing of lower tensile strength. Through this practice joint efficiency has been maintained at 100% with less increase in diameter through the coupling section. Much remains to be accomplished in securing higher joint strength without unduly increasing casing cost or decreasing casing clearance.

Boilers [8]. Improvement in oilfield boiler design has kept pace with improvement in other equipment at the rotary rig. Some improvements are covered by A.S.M.E. and A.P.I. codes, and hence are general for boilers built to comply with these codes. Other features are optional and there is no general agreement upon these features.

Increased firebox capacity with decreased tube-length gives a more portable boiler without sacrificing overall efficiency. The arched crown sheet is a recent feature added which permits stay-bolts to be threaded-in normally to the sheet to give more effective threads and also permits the placing of more tubes in the top row. Thermic siphon equipment for better circulation is featured by some makers of boilers. Superheat boilers have had a rather widespread trial in connexion with oilfield development within recent years. While increased efficiency in steaming is recorded, the advantages for oilfield use have not been so great as was anticipated, with the result that a number of contractors and operators are returning to the use of saturated steam. While superheat steam reduces energy losses in transmission; is more desirable where piston-type valves are used in the prime mover; and increases the boiler capacity, these advantages are to a degree offset by increased investment; increased equipment which must be installed and serviced; and the addition of a serious problem in lubrication.

Listed as improved accessory boiler equipment are:

1. Automatic fuel, water, and blower regulators.
2. Shorter stacks with blowers which under difficult conditions for transporting may permit the omission of one boiler if efficiency is a matter of secondary importance.
3. Low-pressure burners of improved types give increased boiler capacity and fuel saving.

Rotary Drilling Bits. The importance of improvement in rotary drilling bits can best be realized from the fact that only a few years ago it was considered necessary to make provision at rotary-drilled wells for a change-over to standard drilling tools when hard formations were encountered. This costly practice was an enforced necessity because no adequate rotary bits were available for drilling hard formations. To-day combination drilling rigs are no longer used for the above reason, although they may be used for drilling into the producing horizon or for some special reason. Recently a wing-type rotary bit drilled over 2,300 ft. within 24 hours. Numerous cases are on record where improved rolling cutter-type hard rock bits have been in continuous service for more than 48 hours while drilling hard rock. In most cases these bits, after making such phenomenal runs, were found to be not exceptionally dull, nor badly out of gauge, and were in fair condition as to the cutter bearings.

The result of this bit improvement has far greater importance than the reduction of bit costs alone. Fishing jobs decrease with bit improvement, but of greater significance is the decreased loss of actual drilling time by increased bit service. The entire drill-pipe column must be removed in sections and later replaced each time a bit is changed.

Rotary bits may be classified as drag bits and rolling cutter type, and these have been dealt with elsewhere.

The selection of the proper bit for given conditions is very difficult because of inadequate data; hence this selection is usually based upon the experience of the operator for the particular area after having tried out a number of bits. The only generalization which will bear inspection is that for laminated formations of low or intermediate hardness the drag-type bit will perhaps make more rapid penetration than the rolling cutter type of bit because the material is removed in flakes or chips much larger than the particles removed by the pulverizing action of the rolling cutter type. However, the shock loads imposed upon drill pipe as the result of using the drag-type bit are more severe than those resulting from the use of the rolling cutter type. The question, then, becomes one of determining whether drill pipe is to be sacrificed for speed in drilling. Within the different classes of bits it is possible to select one of several which will give about equal performance under similar conditions.

The improvement afforded by the newer drag-type bits has been largely accomplished through the use of superhard materials applied as facings on the cutting edge and lands, or by the use of superhard materials inserted in the cutting edge and built up with superhard facing material. The rolling cutter-type bits have been improved by the application of hard surfacing material on the lead side of the cutting teeth and at such position upon the roller as to keep the bit out to full gauge. The wash pipes or water-courses of bits have also been improved by lining with superhard material. In both of the leading makes of roller-type bits, bushings have been replaced by roller bearings and lubrication is accomplished by the mud fluid. A wider range of adaptability has been furnished in the rolling cutter type by a variation of the amount of material in the cutting teeth. For softer formations less material is included in the teeth and the teeth are more widely spaced.

One opportunity for increasing the capacity of bits lies in the study of the proper arrangement and size of water-courses. There is evidence that the high-velocity jet of mud-laden fluid directed upon the cutter is responsible for the removal of a considerable portion of the metal from the cutter. This is estimated to be rather high, especially where the cuttings are recycled because of improper treatment of the mud at the surface.

Prime Movers. New features introduced in steam-engine construction are:

1. Vertical type for some engines.
2. Hand-controlled variable cut-off. This has passed the experimental stage and has been shown to be effective in fuel saving.

3. The fully balanced inside admission-type piston valves.
4. 14 × 14 in. have replaced 12 × 12 in. twin steam-engines at some of the deepest drilling wells within the past year.
5. The practice of placing a full-sized auxiliary twin engine in the cellar or below the substructure has been introduced quite extensively, especially in California.

Internal-combustion engines have passed the experimental stage and the method of power transmission or power take-off has been successfully solved by various remote control clutches and counter-shafts.

The Diesel engine within the past two years has been proved satisfactory when used to drive through counter-shaft and clutch, or when used to develop direct-current power as explained in a later section of this article. An experimental set-up is now under test in California for the direct-drive reversible Diesel engine.

Draw-works. New features in draw-works construction include unitized skid-mounted jobs with hydromatic braking in addition to friction braking (Fig. 6). Mounting as a unit permits better service from friction-type brakes by virtue of the fact that adjustment of tension in the brake-bands is not affected by the load carried on the derrick floor. Grooved drums are now being used. It is estimated that the unitization of draw-works has increased the service of chains and bearings by at least 20% because better alinement and better lubrication are possible where the draw-works remains intact as a unit.

Derricks. No startling developments have been made in derrick construction. The 122-ft. derrick continues to be the popular choice for all except very deep drilling. Operations during the past year indicate that for the deeper wells the 136-ft. A.P.I. derrick is becoming almost standard. The present-day derricks are highly portable, and for most of the popular makes the strength has been increased where stress analysis has dictated, with the result that far fewer derrick failures occur for present deep drilling than formerly occurred for shallow drilling when stress loads were not analysed.

Control Equipment. Control equipment at the rotary rig has now become standard equipment. In addition to making use of various single-shot devices for measuring the declination from vertical, drillers are now interested in knowing the torque load transmitted to the drill pipe and the rate of rotation of the drill pipe as well as the amount of weight carried on the bit. This latter knowledge has been considered important for a number of years. The five-point control equipment shown in Fig. 7 is a relatively recent development. In addition to these instruments of control, drillers are making use of instruments for checking the character of rotary mud.

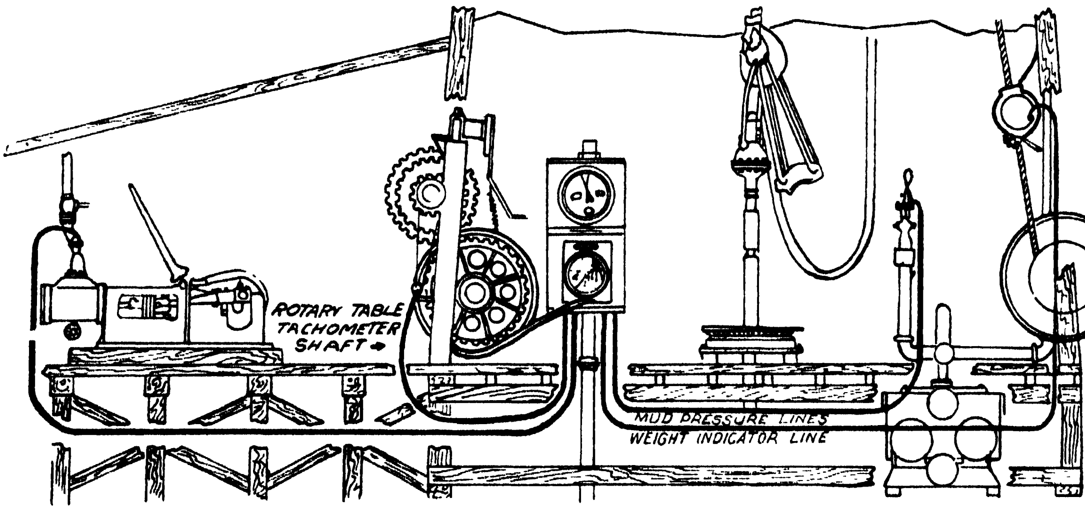


FIG. 7. Schematic illustration of a control instrument including the weight indicator, the super-sensitive Vernier weight indicator, the torque gauge, the slush-pump gauge, and the rotary table tachometer.

Mud Pumps. The general trend in mud-pump design has been towards greater volumes and higher pressures. Fig. 8 shows a recent development for reducing steam consumption (usually about 65% of the steam consumed at a steam rig is chargeable to the mud pumps). The illustrated drive from an engine with variable cut-off, through a gear box, is said to effect a saving of more than 10% in steam consumption.

Condensers and Preheaters. A recent innovation is shown in Fig. 9. Here a hot and cold pump are mounted on skids with the stand-by feed-water pump. The 5 × 6 × 12-in. simplex double-acting cold pump introduces feed water into the condenser box through a spray jet. The cold-pump valve is automatically controlled by the water-level of the condenser. Exhaust steam from engine and pumps is introduced in open contact with the feed water through the flanged connexion at the upper left of the condenser chamber. The 10 × 6 × 12-in. simplex double-acting hot pump takes suction from the condenser chamber and discharges the preheated water into the boilers. The hot pump is manually controlled. Under test a saving of 12·5% in feed water consumed and 13% in fuel saved is shown.

The present trend in equipment design is to maintain equipment capacity with decreased weight for equipment. Use of better materials; unitizing; improved lubrication; better alinement; improvement in bearings; better support for shafting at points of stress concentration, and numerous other improved design practices have within the past two years superseded the practice of securing greater ruggedness through the addition of larger quantities of metal. The greatest limiting factor in extending this trend is the abuse imposed upon rotary equipment by the present use of the positive jaw-type clutch.

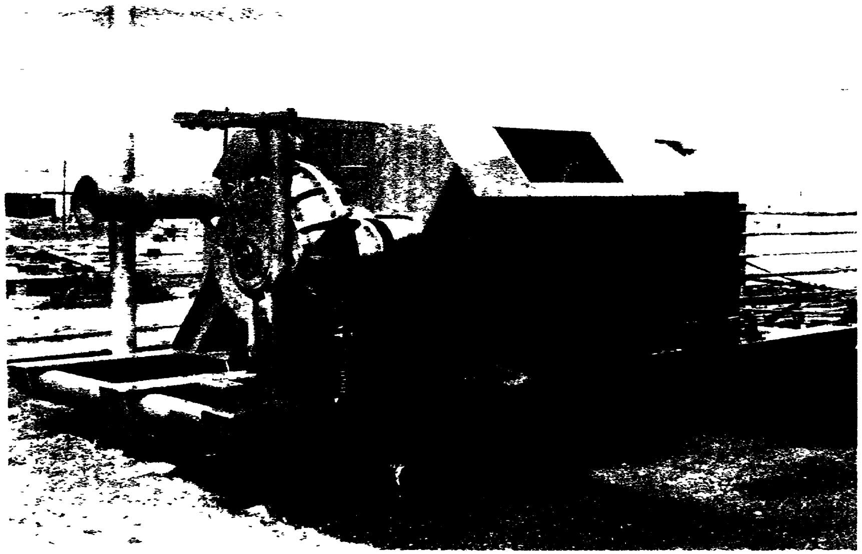


FIG. 6. A modern unitized, skid-mounted draw-works with hydromatic brake

FIG. 8. View near Chase, Kansas, August 1935. An 'Oilwell' No. 7 (7¾ × 7 in.) vertical twin-cylinder steam engine driving an 'Oilwell' No. 14-P (7¾ × 14 in.) power slush pump

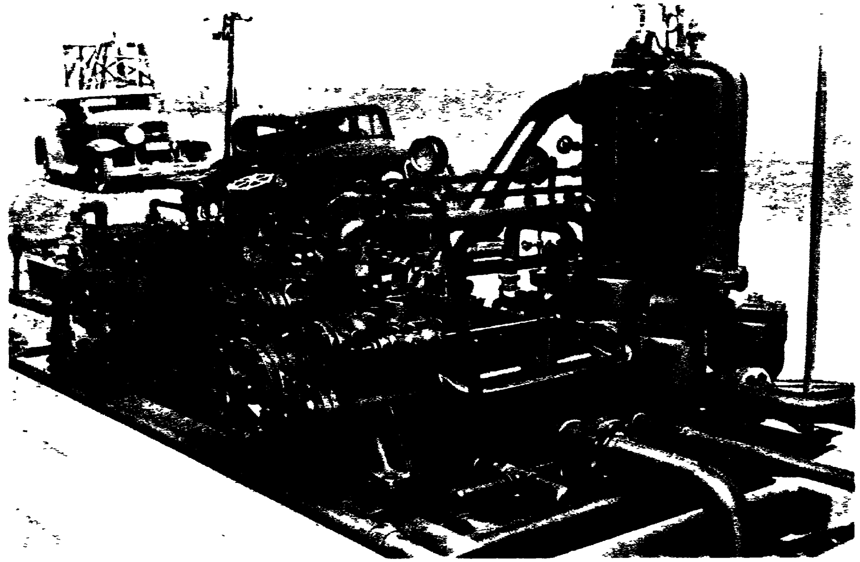


FIG. 9. View near Houston, Texas, June 1935. An 'Oilwell' feed-water heater pump (open type) installed with a Wilson-Snyder 7 × 4½ × 10 in. boiler feed pump (auxiliary or stand-by) and two turbo generators on one set of skids

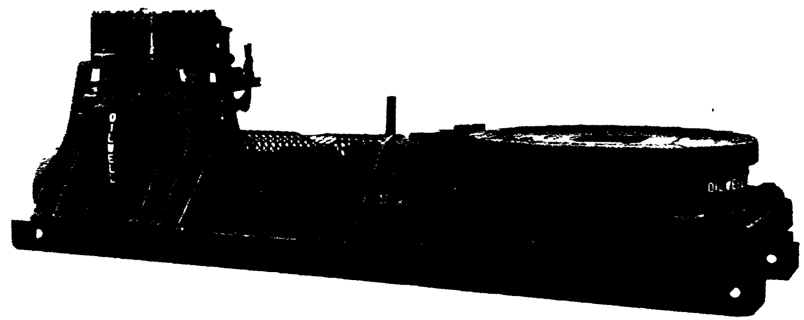


FIG. 12. An 'Oilwell' rotary drilling unit providing a direct drive to the rotary from a small vertical twin-cylinder steam engine

Securing Drilling-tool Efficiency

The primary tool used in the actual drilling of a deep well by the rotary method is a long and exceedingly delicate one. This composite tool consists of a bit or cutting tool at the lower extremity. Next above the bit are the drill collars, which are large-bore, hollow shafts held together by suitably threaded connexions. Above the drill collars is thin-walled, hollow sectional drill pipe coupled by tool-joints or by drill-pipe couplings. At the top of this hollow shaft is a hollow kelly joint by means of which, by a properly adapted turntable, the composite tool is rotated.

The entire shaft is supported by a swivel, hook, travelling block, crown block, and a wire line reeved through the blocks in a manner to give the desired number of supporting lines. The live end of the steel wire line is spooled on the drum of the drawworks.

The actual cutting of the material from the bore hole is accomplished by the rotation of the cutting tool or bit, powered by a prime mover acting through the rotary table and hollow shaft and by the application of a desirable weight upon the bit.

The material displaced by the bit is removed from the bore hole by the circulation of a fluid, usually mud-laden water, down through the hollow drill pipe and water-courses of the bit, thence upwards through the annular space between drill pipe and bore-hole wall to the settling pits at the surface.

Assuming that the equipment is adequate for satisfactorily removing formation cuttings, hoisting the drill pipe, and performing secondary operations at the well, that which follows constitutes an attempt to analyse the chief causes of failure of the composite drilling tool and to set out corrective measures to secure highest efficiency from this drilling tool.

In a foregoing paragraph it was stated that the composite drilling tool is very delicate. One would not be forcibly impressed with this fact from observing the relatively stiff sections of the drill-pipe stands as they are racked in the derrick, yet if a sufficient number of these individual sections are considered joined together to form a single boring tool 7,500 ft. in length and 4½ in. in diameter, a true picture will be obtained of the slenderness of the tool with which wells are now being drilled to a depth of 2 miles. The same slenderness would be given by a hollow steel wire 20 ft. in length, with an outside diameter of 0·012 in. and a wall thickness of 0·0009 in.

The necessary consideration is the mechanical means by which to secure the maximum rate of cutting and the ultimate footage drilled with such a composite tool, which ultimate work must further be accomplished with a minimum number of failures in the drill-pipe section and a minimum deviation of the hole from vertical.

There are three principal types of drill-pipe failures. Listed in the order of the frequency of occurrence (except for worn-out drill pipe) these failures are [1, 1935]:

1. Failure in one of the full stand-off threads above or below a tool-joint.
2. Failure in the plain section and immediately adjacent to the upset.
3. Twist-offs.

The first of these may be started in the lathe or threading machine by producing an undetected fracture, or it is remotely possible that there is induced a crystal structure easily subject to fatigue failure. Where the end section is of uniform diameter, that is, not upset, the cutting of threads will (especially if the threads terminate in a sharp angle) produce a sudden change in cross-sectional area, which in turn is responsible for the concentration of repeated flexing stresses at the last full thread. While this type of failure will continue to be in evidence for drill pipe that is not upset, it may be greatly reduced by the following practices [17]:

1. Proper design and cutting of threads. A more nearly U-shaped thread would probably be desirable.
2. Completely making up the tool-joint on the drill pipe at the factory and permitting a minimum number of exposed full threads.
3. Accurately machining a square or taper shoulder to receive the pipe in concentrically tight fit and thus strengthen the exposed threaded section.
4. Shrinking the tool-joint on to the drill pipe at the factory.
5. Improving the steel alloy.

The second type of failure is due to fatigue from recurring flexure stresses concentrated at the point of most pronounced change in wall thickness, between the plain section and the upset. Corrective practices at the mill can perhaps go no further than to produce a fully normalized end section with a uniformly symmetric taper from upset to plain section.

The third type of failure is properly named a twist-off and occurs when the plain section is subjected to a torque load greater than it is capable of withstanding. The manufacturer cannot overcome this type of failure, but it is possible to delay its time of occurrence for the particular drill pipe by a substantial improvement in quality of drill-pipe steel, and uniform wall structure.

The principal stresses or shock loads to which the composite drilling tool is subjected are:

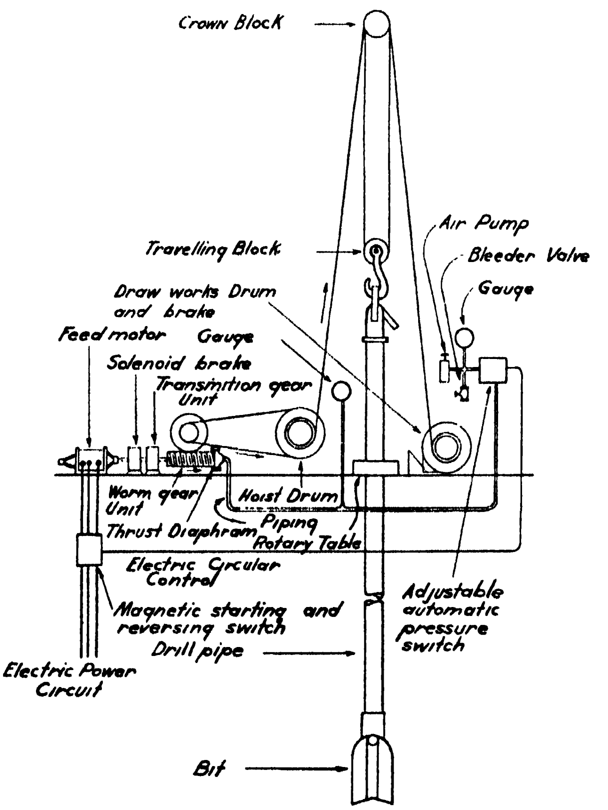
1. Flexing stresses produced by rotation of the drill pipe under compression.
2. Shock loading produced by a sudden application of too much weight.
3. 'Stall-shock' produced when the bit is released from a stalled position with the consequent snap-back of the drill pipe.
4. Torque failures resulting from the application of a greater torque load than the drill pipe can withstand.

The first of these stresses, and perhaps the most vital, is the flexing stress induced as a result of drill-pipe rotation while under compression. Obviously, then, the solution should be rotation with the drill-pipe section under tension. Heavy bottom-hole assemblies consisting of large-bore hydraulic pipe or drill collars have been used just above the bit. The total weight of this stiff section of hydraulic pipe should, theoretically, equal the maximum weight which will be applied at the bit, in order that the point of change from tension to compression will in all cases fall within the rigid bottom-hole assembly. However, at the majority of rotary drilling rigs the drilling tool is fed into the formation manually through the drum brakes. This method of applying weight to the bit results in recurring applications of abnormal weights which advance the point of change from tension to compression to a higher position in the string. The weight of the rigid section should be sufficiently greater than the weight normally applied to the bit to maintain this point of change within the rigid section at all times. Just what this ratio should be has in general not been defined. It has been suggested that the weight of

the heavy bottom-hole assembly should exceed the weight applied at the bit by 50 or 100%.

A review of data obtained at a large number of wells indicates that the effect of using heavy bottom-hole assemblies was to increase the rate of drilling and reduce the average and maximum deviation.

As the boring tool penetrates the earth's crust, formations of varying hardness are encountered. The degree of hardness may vary from soft formations capable of being drilled at the rate of 100 ft. per hour to hard formations



SCHEMATIC DIAGRAM G-E AUTOMATIC WEIGHT CONTROL

FIG. 10.

which may not be penetrated at rates greater than 1 in. per hour. It is also possible that a very soft formation may lie next above an extremely hard formation commonly referred to as shell. It is further possible that boulders will be encountered by the bit. Assuming that the cutting tool is being advanced into the formation at the higher rate, the bit will have a tendency to 'dig into' the hard formation when it is encountered. This results in the stalling of the bit momentarily, after which the bit will release or, in extreme cases, it may be necessary to decrease the weight upon the bit before it is released and thus permit drilling to be resumed. So long as these conditions are encountered with uncontrolled advancement of the cutting tool into the formation, drill-pipe failures may be expected.

The difficulty of failure might be largely overcome by using bits of the rolling cutter type instead of the drag or fish-tail type except for the fact that for certain areas it may be economically more desirable to choose the more rapid method of drilling with the drag-type bit at the expense of the drill pipe.

Another method of reducing drill-pipe failure and avoiding deflexion of the bore hole is that of making use of one of the automatic or semi-automatic feed controls for the purpose of advancing the cutting tool into the changing formations at a uniform rate, maintaining so far as possible a constant weight upon the bit. The Hild differential used with electrically powered rigs and the Halliburton differential control used with steam rigs have been known to the industry for a number of years. The General Electric drilling control (Fig. 10) may be used at any rig regardless of type. Electric power at the rig, however, is a necessity. This control makes it possible to advance the bit with a constant amount of weight applied at the bit at all times.

A recent development in feed controls is the Brantley drilling control (Fig. 11). This control requires no prime mover for its operation. The tension in the live end of the wire line drives through the drum shaft and through a speed multiplier to a multiple cylinder pump which regulates the rate of feed by the volume of liquid pumped. The weight carried on the bit is determined from the weight indicator and is adjusted at the driller's stand by simply throttling the valve which varies the discharge head on the pump.

In the past, although the composite drilling tool is the unit which should have received major consideration, the tendency has been to adapt the prime mover to the hoisting unit. This has led to the use of large prime movers operating through heavy hoisting equipment in transmitting power to the rotary table.

The present necessity for drilling large bore holes disturbs the balance between cross-sectional area of the drilling string and the upper section of the bore hole with consequent torque loads upon the drill string out of all proportion to their capacity to absorb these torque loads. In order to minimize these excessive torque loads, maintain a rapid rate of penetration, and keep the hole reasonably straight, higher rotative speed and decreased weight upon the bit is necessary. The use of large prime movers driving through the typical draw-works to the rotary table does not lend itself to high rotative speeds because of certain practical difficulties. When rotative speeds are increased from 80 r.p.m. to more than 200 r.p.m. the linear velocity of the roller chains through which the drive is accomplished is increased to the point where it is impossible to secure satisfactory service from these chains. Further, the energy stored by virtue of the momentum of these oversize prime movers and the oversize units through which the prime movers act, together with the excessive horse-power developed by these large prime movers at high speeds, transmits an excessive torque load to the drill pipe, especially when too much weight is applied or when for any reason the cutting tool tends to stall. A recent practice makes use of a small prime mover used for direct drive to the rotary (Fig. 12). Here it is preferable to avoid as far as possible intermediate parts which might store energy at high rotative speeds. The size of the prime mover employed for this purpose should not be capable of developing a greater torque load than the drill pipe, regardless of its condition, is capable of absorbing without failure. The results from a somewhat widespread trial of this principle are sufficiently encouraging to warrant a prediction of the extensive use of small prime movers, directly connected to the rotary table, to achieve a wide range of rotative speeds.

It has been mentioned that there is a recent trend towards high rotative speeds with decreased weight applied at the bit. That this trend is productive of good results can be stated as a generalization which is true; but it is impossible

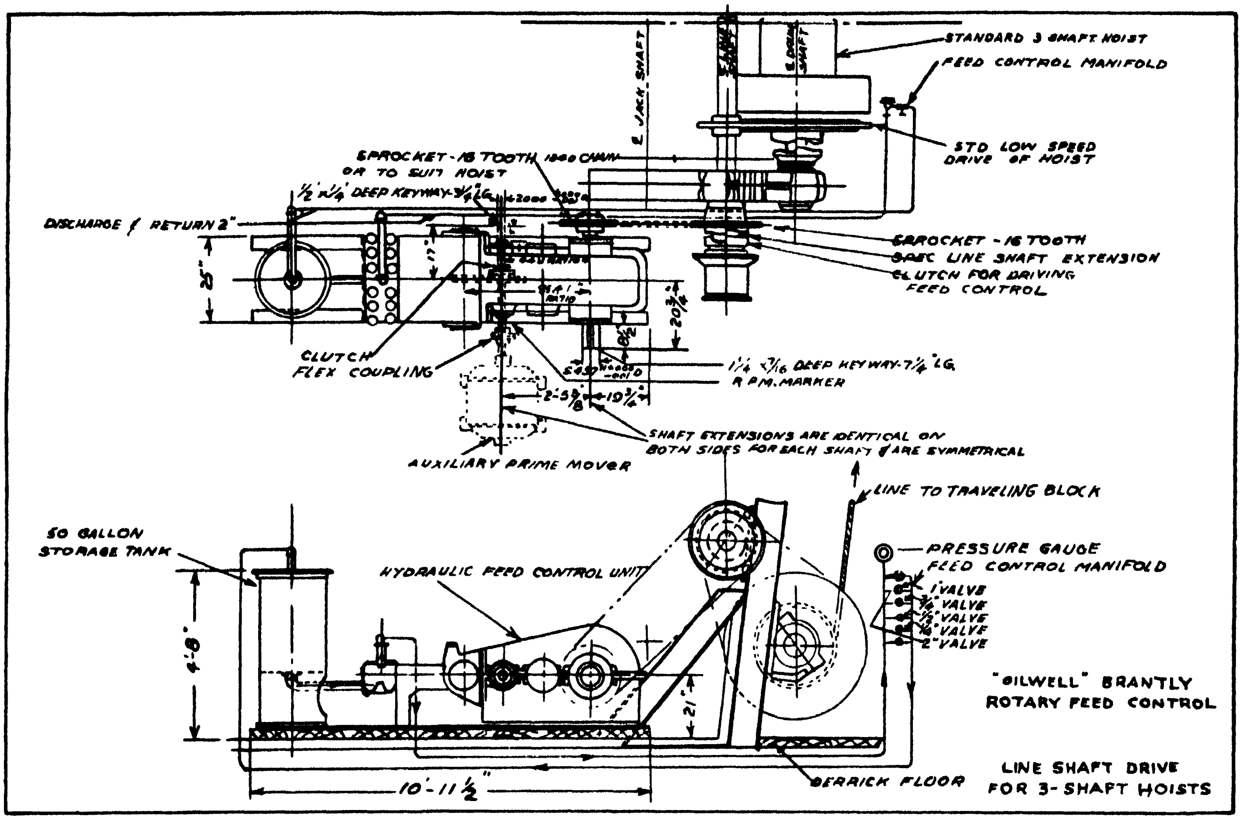


Fig. 11.

to designate any given rotative speed or any given weight for any certain area. Differences in areas, formations drilled, equipment used, all are variables which make it impossible to specify to drilling crews specific weights to carry and specific speeds of rotation [16]. Furthermore, drilling is more an art than a science, hence it is unwise to forget the personal equation introduced by the driller operating the rig.

The purpose of high rotative speed is to maintain a satisfactory rate of drilling when the weight carried upon the bit is reduced. The purpose of carrying less weight upon the bit is to avoid deflexion of the bore hole and to impose upon the composite drilling tool less destructive loading.

The fundamental principles consist of applying the correct weight upon the bit through heavy bottom-hole assemblies so that the drill pipe may rotate while under tension and then increase the rotative speed sufficiently to maintain a satisfactory rate of drilling. These factors must be chosen upon the basis of experience within the area under consideration.

Improved Casing Practices

A few years ago it was predicted that wells could not be completed to depths now quite common because it was believed that casing would not hold together at depths of 8,000 and 10,000 ft. To-day, however, casing is set in deep wells with fewer failures than when 5,000-ft. wells were the deepest in the country. Improvement in the strength of casing is partially responsible for these results, but the improved methods for placing casing in the well are equally important. The truth of this is illustrated by the recent accomplishment of the Union Oil Company of California in setting a string of $8\frac{5}{8}$-in., 36-lb. standard A.P.I. casing to a depth of 9,081 ft., whereas the recommended ultimate depth for this particular casing is 7,640 ft.

Careful inspection and handling of casing at the factory and in the field has minimized casing failures.

Casing elevators and casing spiders shown in Figs. 13 and 14 make use of long trunion-mounted slips and engage casing firmly without damaging the casing.

Equipment for running casing has been greatly improved. Composition casing guides and float collars (Fig. 15) permit the casing to be floated into the well, thus relieving the casing of unnecessary acceleration loads. The use of high tensile strength casing for the upper section which carries the heaviest load and standard casing for the lower section of extremely long casing strings is another new feature.

The practice of loading the casing with rotary mud to equalize the pressure from without the casing has almost eliminated collapsed casing while it is being placed in the well.

Under-reaming the lower section of the hole so that a more substantial cement body will constitute

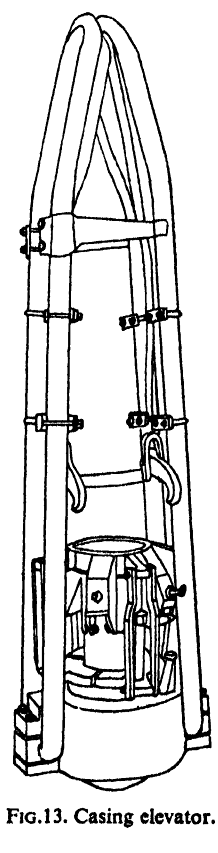


Fig. 13. Casing elevator.

a better casing seat is a recent practice now followed by a number of companies. A variation of this practice is the use of flush-joint casing at the lower portion of the casing string to give greater clearance in the hole drilled below the cemented casing than could be obtained with heavy coupling-type casing.

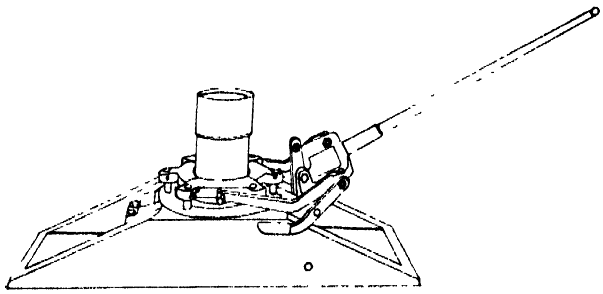
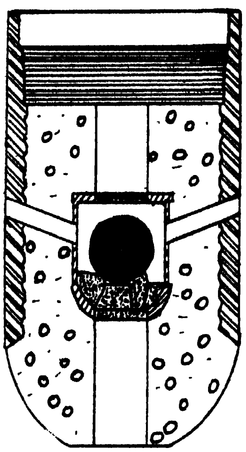
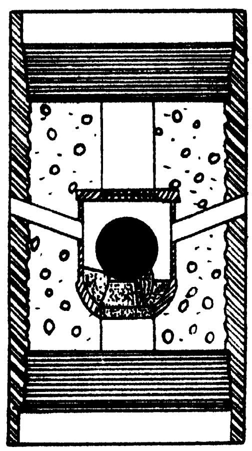


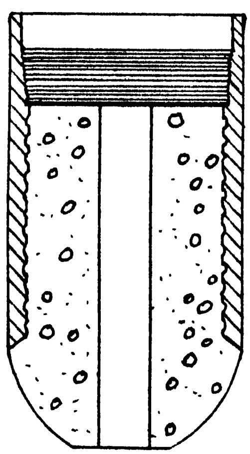
Fig. 14. Automatic casing spider.



Casing guide with float.



Float collar.



Casing guide without float.

Fig. 15.

Finally, the tremendous increase in the amount of cement placed behind these long strings of casing furnishes a reinforced wall at the back of the casing which operates to reduce the hazard of casing collapse as soon as the pressure within the casing is relieved. In some instances the cement body behind the casing extends more than 4,000 ft. above the casing shoe.

New Developments in Cementing Casing

The technique of placing large quantities of cement behind long strings of casing has improved and kept pace with the newer demands created by deeper wells and higher formation pressures.

Equipment for placing cement has improved. The trucks have increased capacities and increased pressure ranges. Cement guides and floats have been improved. Multiple stage cementing has demonstrated its superiority for certain instances, and with few exceptions the cementing operations in conjunction with development work have kept pace with the demands.

Cements which will produce a uniform slurry without a great deal of agitation are now offered to the industry by a number of companies. Aquagel cements have been developed so that it is now possible to reduce the density of cement from 16 lb. per gallon to 12½ or 13 lb. This is especially desirable where there is a tendency towards lost circulation.

The major problem in cementing casing in deep wells is the hazard of high temperature. It is not unusual for these temperatures at the bottom of the well to greatly exceed the boiling-point of water. It is a well-known fact that if the temperature of a neat cement slurry rises above room temperature the setting time of cement is greatly accelerated. The curve in Fig. 16 shows graphically this accelerated setting due to increasing temperatures.

From these facts it is obvious that where it is desired to place large quantities of cement behind the casing in the presence of high well temperatures, the elapsed time for the setting of the cement slurry allows no margin of time to provide for the probable temporary failure of cementing equipment.

In the past the situation has been partially met by one of two or a combination of two practices. The first of these is to reduce the amount of cement placed behind the casing, which, of course, reduces the elapsed time necessary to pump the cement to the back of the casing. Many deep wells to-day are being cemented with from 250 to 500 sacks of cement where it would be desirable to use 1,000 or more sacks. The second method by which this high-temperature hazard has been combated, with indifferent success, is the addition of ice to the circulating pits to cool the formations temporarily to the point where the cement slurry may be pumped to the back of the casing without too much hazard, or the addition of ice to the mixing water. The amount of ice required has been largely a matter of opinion and varies from 10 tons to amounts in excess of 100 tons. The time required to accomplish the cooling of the formations is also a matter of conjecture and ranges from 24 hours to several days. The difficulty of maintaining the proper characteristics of the mud fluid where such large quantities of potential water are added becomes, in some instances, quite a problem and requires the use of admixtures and careful mechanical control at the surface. Additional expense involved due to cost of the materials, rental on tools, and delayed completion of the well is in most cases excessive. The degree to which the difficulty is overcome is in many cases problematical. Some years ago a chemical retarder was developed to control the fluidity and the setting time of neat cement slurries. This retarder has been subjected to continuous laboratory tests to eliminate any undesirable characteristics and to adapt its use to oilfield cementing with cement equipment as it exists to-day.

Curve 1 of Fig. 17 shows the setting time for an untreated

cement plotted against varying temperatures. Curve 2 of the same figure shows the amount of retardation where 1% retarder is added to the same cement as used for curve 1. This difference in setting time may be increased or decreased, depending upon the amount of the retarder added to the cement at the mill.

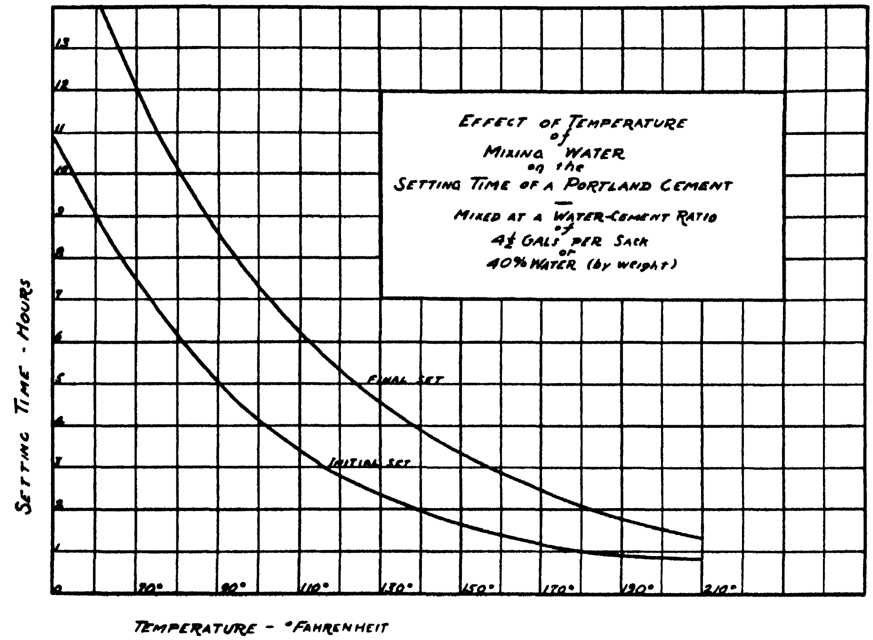


FIG. 16.

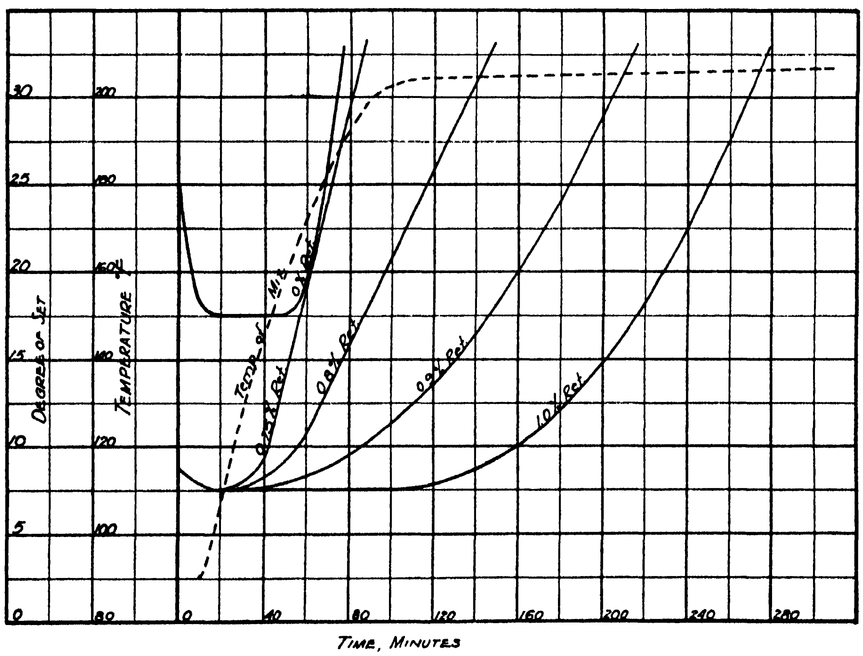


FIG. 17.

This invention gives promise of being the most outstanding recent development in the cementing of oil-wells and will undoubtedly find a widespread use for all oil-well cementing jobs at depths exceeding 5,000 or 6,000 ft.

Control of Rotary Drilling Mud

Drilling mud functions under two distinct sets of conditions. The first of these obtains where drilling proceeds under conditions which present no particular problem from the standpoint of formation and where the formation penetrated will furnish adequate clay suspensoids to give proper body to the drilling mud. Even under these favourable conditions a great deal of trouble has been encountered and is being encountered at present. Much trouble is occasioned because of lack of knowledge of what constitutes a good drilling mud. One class of driller demands light, non-viscous muds for all conditions, while another group believes that a highly viscous mud is the proper drilling fluid for most formations, and the balance maintains a position somewhere between these two extremes. Another factor which complicates the mud problems at the well arises from the fact that some drillers realize that rapid

footage can be secured where the mud is extremely thin.

In general the following characteristics are desirable for ordinary drilling: (1) the weight should be maintained at a point which will not add too great a burden to the slush pumps, probably 70 to 75 lb. per cu. ft.; (2) the viscosity should be maintained at a point sufficiently high to carry the cuttings from the hole, yet not high enough to slow up drilling progress or prevent the mud stream from dropping out cuttings as it passes through the settling pits; (3) gel strength and gel rate should be maintained at such a point that when the tools come to rest in the hole and circulation is discontinued, the rate of settling for the cuttings held in suspension will be retarded. If gel rate and gel strength are too great, however, the cuttings will be recycled instead of settling out in the pits.

Ordinary drilling conditions do not, as a rule, cause any undue difficulties, but graver conditions exist and will be considered here singly, although these conditions seldom present themselves singly.

Blow-out is a condition in which the gas pressure or fluid pressure from the formation exceeds the hydrostatic pressure exerted by the mud column. In certain fields the fluid pressure is much higher than the pressure of a water column equal to the depth of the formation. Here we have potential blow-outs for every well drilled. Sometimes high pressures from a deep sand escape to a shallow sand, thus creating an abnormal pressure near the surface which forms a blow-out hazard. A third cause for blow-outs is occasioned where improper control of the mud fluid permits the mud to become so viscous that it does not give up occluded gases in passing through the pits or over the screens. In this event the density of the mud may fall below the density of water.

Remedies as practised to date include: (1) adding weighting material (material having a specific gravity above 4) to the mud fluid, which usually necessitates the addition of a colloidal clay to enable the mud to carry the heavy material; (2) drilling under pressure is a second method of preventing blow-outs. Drilling under pressure consists of drilling through some packing device and maintaining back-pressure upon the mud discharge.

It is safe to predict that as pressure-drilling equipment becomes simplified and less expensive, many mud problems encountered in abnormal cases will be controlled mechanically rather than by attempting to regulate the character of the mud. It naturally follows that any attempt to raise the specific gravity of the mud materially above that produced by the clay particles of the formation being drilled presents increasingly difficult problems from the standpoint of controlling other mud characteristics which are equally as important as mud density.

Many unnecessary blow-outs occur because the mud is badly gas-cut before the crew is aware of it. A decrease in density does not always follow a limited amount of gas-cutting, and gas-cutting is only one of several causes for decreased density. The bubbles which are not released in passing through the circulating pits are very minute. It is therefore possible for a mud having a satisfactory appearance to be in urgent need of reconditioning. Reconditioning should begin with the first tendency towards gas-cutting because considerable time is required to alter several hundred barrels of mud. An instrument has recently been placed upon the market for making a quick and accurate determination of the percentage of gas retained in the mud fluid. It can be operated by any member of the drilling crew, and the percentage of gas-cutting can be read directly from a graduated scale upon the instrument. Such an instrument should be standard equipment at every well where a blow-out hazard exists.

Lost Circulation is a term which defines a condition in which certain porous or fissured formations penetrated fail to exert sufficient pressure to prevent the cycled mud fluid from penetrating these formations. The degree to which circulation is lost ranges from a few barrels per hour to complete loss of circulation into cavities which cannot be sealed off.

Corrective practices include:

1. Changing from rotary to standard tools where it is impossible to re-establish circulation.
2. Intermittent cycling of a partial column of mud has been successful in a few cases.
3. Sealing the formation by spotting successive batches of neat cement.
4. Sealing the formation by introducing cotton-seed hulls or other fibrous materials into a gel-type mud.
5. In mild cases it is possible to adjust the density of the mud so that a minimum of lost circulation exists.

Brine Dilution of Rotary Mud. It frequently happens that under certain conditions brine-water from the formation dilutes the mud column. The addition of this brine-water does not react in the same manner as the addition of ordinary water. In addition to the expected thinning of the mud by reducing the solids-to-liquid ratio there is a definite precipitation of the suspensoids. While certain changes in *pH* values are caused by the addition of salt-water, the effect of this change would perhaps only account for increased fluidity and not for the precipitating reaction. The 'brine effect' has long been recognized. In the light of present evidence it is probable that the metal sodium ion neutralizes the charge on the clay particle.

Remedies include: (1) addition of new colloidal clay; (2) chemical treatment to restore the electrolytic medium to its original condition.

High-temperature Problems. The partial solution of high-temperature problems has been accomplished through the use of a natural clay or the treatment of the clay at hand to produce a mud which forms a thin impervious seal at the face of the hole. In general it has been found that the type of mud which produced a seal ranging from $\frac{1}{32}$ in. to $\frac{1}{8}$ in. produced a more satisfactory seal against loss of water than a mud which builds a thick wall on the face of the bore hole.

There still remains the possibility of chemical treatment to minimize the baking effect encountered from high temperatures. This is altogether within the realm of possibility, since within the past few years the equivalent effect has been accomplished where hydraulic cements are used under high temperatures.

Considerable work has been done with the object of adding fibrous material to rotary muds to produce a wall seal consisting of an interlacing network of fibrous materials which form bonding material for congealed mud.

The value of careful control of rotary mud at the well has been clearly demonstrated by earlier investigators, and many contractors and operators now place a trained man at one or more drilling wells to regulate the character of the mud, and, in many instances, to extend research to include new phases of the problem.

The use of mechanical devices such as vibrating screens for eliminating coarse cuttings from the mud is now quite

common. Mud scales or mud hydrometers and some type of viscosimeter are now commonly found at the well. A mechanical device which makes it possible to determine the percentage of gas retained in the mud should be standard equipment at every drilling well. Usually a supply of weighting material and some bentonitic clay, together with equipment for mixing, are a part of the equipment at the well. Usually some well-known chemicals with instructions for application are easily available for quickly restoring or altering the character of the mud to meet given conditions. Mud-pump pressure gauges are being used in increasing numbers.

Individual and co-operative laboratories in close contact with field studies are daily adding to the store of knowledge concerning the many baffling rotary mud problems, and young men are being given specific training in this phase of development work.

In the past investigators have been seriously handicapped because the equipment used for studying rotary muds and the terms which are used to describe the characteristics of rotary mud have been largely borrowed or adapted. Perhaps the greatest future contribution which could be made to this study would be the development of equipment and standardization of descriptive terms suited to the peculiar nature of this substance.

Controlled Directional Drilling

This term defines drilling procedure which purposely deviates the direction of the bore hole by a definite amount. The process consists of two operations. The first of these makes use of one of the several reliable directional survey instruments for maintaining a directional log which fits the programme and gives the horizontal position of the bottom of the hole with reference to the derrick floor at all times. These surveys should preferably be made at the end of each 50 ft. of new hole drilled, although under some conditions it is sufficient to survey at intervals of 100 ft. The second step involves the actual deviation of the direction of the bore hole with the drilling tools.

Directional drilling may be for the purpose of deviating the hole at a definite number of degrees and in predetermined directions to finish the hole at some point in a given horizontal direction from, and a definite horizontal distance from, the centre of the derrick floor. Directional drilling may also be used for the purpose of straightening a crooked hole and finishing the well at a point vertically below the centre of the derrick floor.

Directional drilling in the past has been employed for drilling under special conditions such as:

1. Bringing wild wells under control.
2. Completing more than one well for a derrick floor where derrick substructures are extremely costly.
3. For completing old crooked holes with a new bottom.
4. For penetrating the producing formation at a point above which it is impossible to set up drilling equipment.

The future would appear to hold a promise for widespread application of directional surveying and directional drilling for an altogether different purpose. For deeper sands the industry has been accepting 10-acre well-spacing because of lack of knowledge concerning the proper area per well to be drained for any given field. A number of companies are now studying the theory of proper spacing for wells for the purpose of securing in any field the greatest ultimate recovery with the fewest number of wells drilled. Whether a new formula is propounded or whether an arbitrary acreage for each well is accepted, any well-spacing programme will have no meaning unless the operator can be sure that the pattern of penetration into the producing sand coincides with that laid out at the surface. In order to accomplish this it is necessary to employ directional surveying in conjunction with directional drilling. Any added cost for this plan of development will be returned several fold through increased production resulting from a uniform pattern of penetration before formation pressures have declined.

Combating Heaving Shales in Rotary-drilled Wells

The problem of drilling through heaving shales is one of the most severe yet encountered in rotary drilling. Published material indicates that very few successful completions are recorded for areas where serious heaving-shale conditions exist.

The term 'heaving shale' is somewhat confusing, having been applied to conditions ranging from slight caving to a heaving of such magnitude that several hundred feet of the bore hole may be filled with disintegrated shale fragments or a string of drill pipe may be neatly sheared off and displaced laterally, never to be encountered again. There is ample reason for this confusion, since caving or sloughing is very apt to constitute the first manifestation of heaving formations.

One of the primary causes for heaving formations may be attributed to the inherent nature of the formations. Much of the shale which shows a tendency to heave upon being penetrated is of the type which readily absorbs water with a consequent volume increase. Other heaving shales, not of the swelling type, evidence a pronounced tendency to disintegrate upon becoming wetted. Hydration, then, becomes the primary cause.

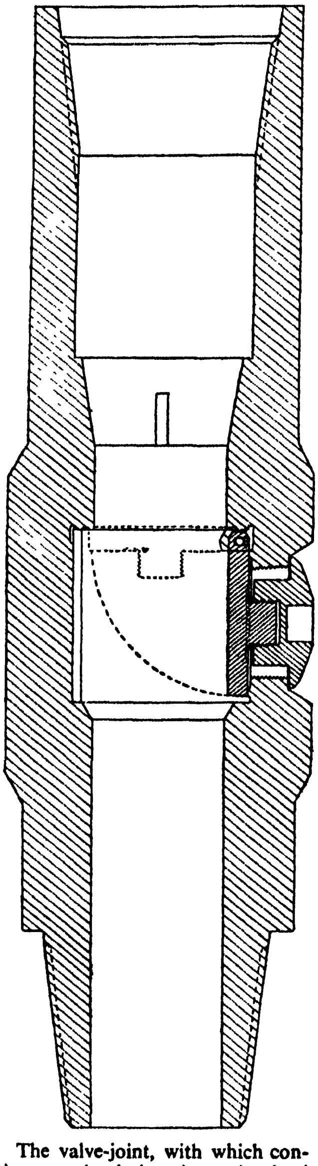
Every core or sample obtained by one company shows slickenside, which is evidence of displacement. It is conceivable that the mechanical cause for this unstable condition is pressure from overburden or tension produced from doming.

As the unstable bed is penetrated by the bit the equilibrium of the bed is disturbed. Sloughing of the walls may produce a cavity in the beginning. This sloughing probably begins as a result of hydration; improper sealing of the walls; circulating too rapidly or too long in one position; swabbing action of withdrawing drill pipe; action of gas blowing shale into the hole; or a combination of more than one of these factors. The inducing of such a cavity naturally leaves a section of the overlying unstable beds unsupported. When for any reason the pressure upon the formation is reduced the first heave occurs. In the process of cleaning out the cavings resulting from this first heave the size of the cavity is increased, thus establishing conditions favourable to another heave. The history of drilling heaving shale beds reveals that heaving becomes progressively more severe from the time when the first caving occurs. The record of failure to overcome heaving conditions, once induced, confirms the theory that the only way to drill through these formations is to avoid the first sloughing. It is too early to claim that the above analysis is the only tenable one.

Attempts to combat heaving shale have made use of several theories. The first line of thought held that a highly colloidal mud must be used to seal the walls of the bore hole, thus avoiding hydration of the formation by infiltration of water lost from the circulating mud. The next

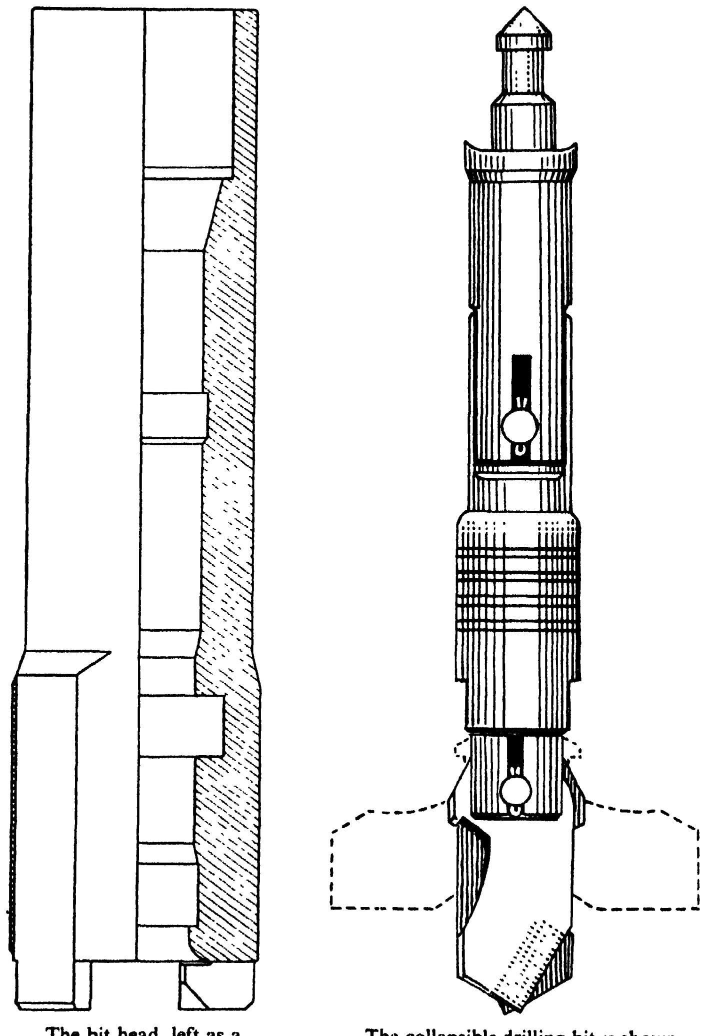
outstanding theory included the addition of an electrolyte to flocculate the colloids and produce an impervious wall seal. Some operators held for an alkaline electrolyte. As a result of this theory a mixture of caustic and crude tannic acid became widely used. The above-mentioned types of colloidal muds plaster the hole by filter action. The walling material is the filter cake, which is produced by loss of

The latest method of conditioning mud for drilling through heaving shales involves the addition of sodium silicate in generous proportions. Sodium silicate reacts with rock-forming materials such as calcium, magnesium, and aluminium to seal the pores of the rocks and thus render them waterproof. Sodium silicate when added to a drilling mud acts in this way to protect the unstable shale against hydration. Further, this sealing action is almost instantaneous, hence more effective than the sealing action secured through the use of the usual colloidal muds.



The valve-joint, with which continuous circulation is maintained when another stand is being added to the drilling string.

FIG. 18.



The bit head, left as a casing shoe after drilling blades are recovered.

The collapsible drilling bit is shown with blades in closed position for pulling out of the hole through the casing. The dotted lines represent the position of the blades when open.

FIG. 19.

water to the formation. This loss of water to the formation causes hydration and disintegration with consequent caving or heaving.

The use of weighted mud for the purpose of exerting greater restraining pressures against the heaving formation possesses merit even when special mechanical or chemical control is attempted. The only disadvantage arising from the use of weighted muds is that the physical and chemical control of the special mud may be complicated to some degree.

While the conditioning of the mud fluid is important, it can scarcely be said to constitute a solution for this difficult problem. In addition to using sodium silicate for treatment of the mud fluid a special mechanical control [3] is employed which makes use of special semi-flush joint casing instead of drill pipe, and a special circulating tool-joint (Fig. 18) for maintaining continuous circulation until the casing used in lieu of drill pipe is landed.

When the heaving formation is reached a string of casing is run and cemented. When rigging up to drill through the

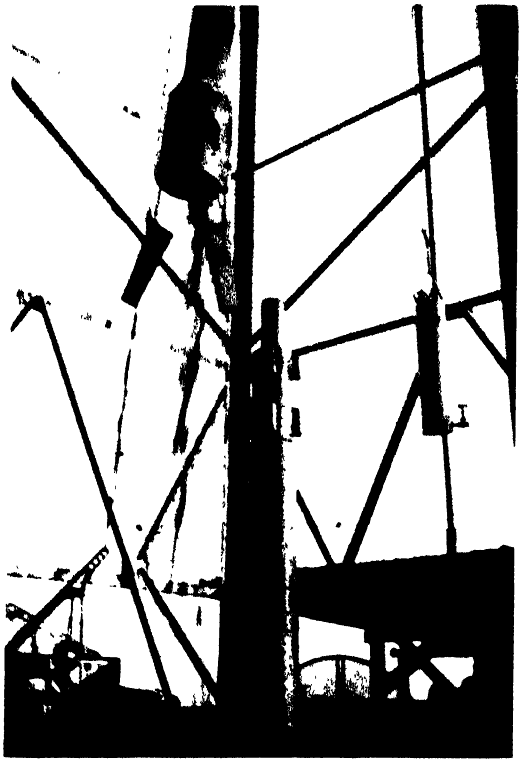


FIG. 20 The hammer stabbing joint being broken out The two wedges in the female end have been knocked out to release it

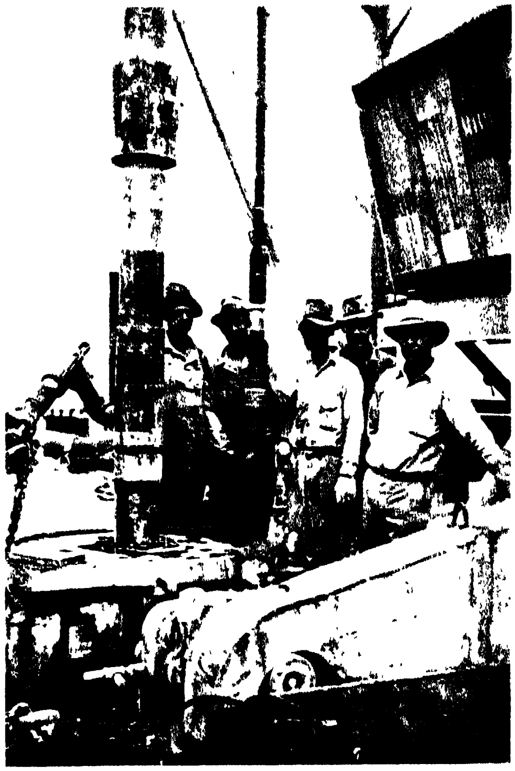


FIG. 20 The hammer stabbing joint as it appears made up. The drilling bit is being held by members of the crew

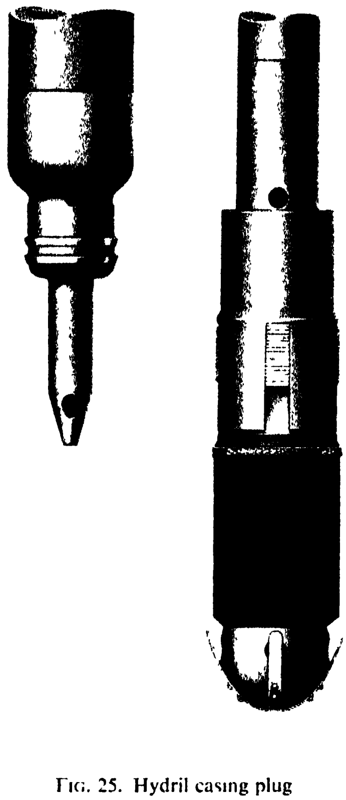


FIG. 25. Hydril casing plug

heaving shale section, a drilling string of special semi-flush casing equal to the length of the cemented casing is made up with a collapsible wire-line bit (Fig. 19) at the lower extremity. This bit may be retrieved by a wire-line fishing tool while the drilling casing remains in the hole, and where it is necessary to maintain circulation while retrieving the bit, the fishing tool is run through a packing gland with rubber cone-shaped packer through which the wire line is drawn under pressure. Circulation is provided by a porthole on the side. A bit made of a bull-plug forging on which four cutting wings are welded and in which adequate water-courses are drilled has also been used. This bit is not retrievable, and when the bit is worn out it is necessary to set casing and reduce the diameter of the hole.

At the top of this string of drilling casing a back-off joint is inserted. Each stand of drilling casing added thereafter includes a circulating valve-joint (Fig. 18).

The casing added functions as a kelly joint, making use of a special drive arrangement. A short sub is made up on the swivel with a hammer-joint (Fig. 20). The joint makes it possible to attach or detach the swivel quickly. When it is necessary to add casing, two joints, with the special circulating tool-joint and the lower half of the hammer-joint at top, are made up and run into the rat hole. In adding the two joints of casing rotation is stopped, but circulation is maintained through the swivel. The plug is removed from the side of the special tool-joint (Fig. 18), and a stand-by rotary hose is connected at this point. Circulation is now discontinued through the swivel and established through the stand-by hose which closes the valve against the upper seat. The double is next hoisted into the derrick and made up in the drilling string, after which the swivel is attached by inserting and driving home the wedges of the hammer-joint. Circulation is now established through the swivel closing the side valve in the special circulating joint as soon as circulation through the stand-by hose is discontinued. In this manner drilling proceeds with uninterrupted circulation and without the necessity of raising the tools off the bottom. When the heaving section is drilled through, or when drilling has proceeded as far as is possible with the existing casing, cement is pumped to the back of the casing and held under pressure until it has hardened. When the cement has hardened, the upper portion of the casing string, including the special circulating tool-joints, is unscrewed at the back-off joint and replaced with regular casing. If the heaving section has not been drilled through, it is necessary to mill up the bit and resume drilling with smaller casing.

Although variations of this technique may be successful, the following rules for drilling through heaving shale have been found imperative:

1. Maintain mud characteristics at values which are known to be best suited to drilling through heaving shale.
2. Use drilling casing rather than drill pipe because the hazard of removing drill pipe, which necessitates the discontinuance of circulation, is too great to be countenanced.
3. Provide a means for uninterrupted circulation from the time the heaving section is entered until it is passed through or until the drilling casing is cemented.
4. In order to avoid the beginning of caving or heaving keep the casing in the hole and avoid so far as possible any interruption of drilling. Stopping to take cores has resulted in the loss of the well in several instances.
5. Keep the hole free from cuttings. In most instances it is necessary to retard the rate of drilling in order to accomplish this.
6. When for any reason penetration is interrupted, the volume of mud circulated should be reduced in order to avoid washing out a cavity.

Pressure Drilling and Well Completion

Pressure drilling consists essentially of the practice of drilling through some sort of packing gland fitted to the well-head through which the drilling tools can be operated. Any satisfactory installation for pressure drilling must provide for running into and withdrawing the drilling tools while the well is under pressure. It must also enable drilling to proceed while holding the necessary back-pressure upon the well.

Pressure drilling is not new to the industry; it has been practised at intervals since 1920. In general, pressure drilling in the past has been confined to those wells where it was impossible to complete satisfactorily wells using artificially weighted mud to offset high formation pressures. In other words, pressure drilling in the past has been practised as an emergency measure where open casing drilling could not be accomplished because of abnormal formation pressures.

Looking to the future, pressure drilling should have a very widespread use for subnormal as well as abnormal formation pressures. The scope of its possibilities can better be comprehended when it is realized that co-ordinated auxiliary pressure equipment makes it possible for the operator to select a circulating fluid ranging in density from a very light gaseous crude oil, through water, to a heavily weighted mud weighing perhaps 150 lb. per cu. ft. Thus equipped, the operator finds it possible to select any combination of discharge back-pressures and fluid densities to cope successfully with formation-pressure conditions ranging from abnormal through subnormal. Pressure drilling in its present state of development makes it possible to drill through high formation pressures without the loss of circulation, and to drill into producing formations using flow from the formation as the circulating fluid, thus completing the well with a clean sand face.

Within the past year wells completed in the new extension to the Oklahoma City pool have recorded bottom-hole pressures less than 300 lb. per sq. in. Pressure-drilling equipment has made it possible to drill into these producing formations with a gasified column of oil, the oil used being produced from the formation. By this method no mud, water, or drilling oil is ever forced into the producing formation itself. The result is a sand face entirely free from the disturbing effects of plugging usually attendant upon drilling-in with mud.

Fishing under Pressure. It is easily apparent that all possible precautions should be taken on pressure-drilled wells to guard against the possibility of a fishing job. Even so, fishing jobs will occur, and it is well to incorporate provisions for this eventuality in the original plans for the lay-out.

The general equipment plan for pressure drilling requires very little alteration to adapt it to pressure fishing or pressure coring. The packing-head assembly should consist of two packers and, in addition, should include a third auxiliary packing head. This third packing head should be placed below the other two and should be of such design that it can be fitted with pack-off rubbers of various sizes to close about drill collar, coring tools, wash-over

string, or an overshot, thus making it possible to lubricate into and out of the hole any string of drilling, coring, or fishing tools.

Pressure Completion of Wells. Drilling into production with pressure-control equipment has distinct advantages where formation pressures are extremely high, extremely low, or where production comes from limestone. The advantage of pressure-drilling equipment in the first instance arises from the fact that the well may be completed without hazard from blow-outs. The advantage in the latter instances lies in keeping mud pressure from partially or wholly sealing off the producing formation. A further advantage, and one which justifies the cost of change-over to pressure-completion equipment, is the ease with which a composite log may be produced during the process of 'drilling-in'. Such a log is shown in Fig. 21. Because of the high velocity of the cuttings from formation to surface, and because the cuttings are free from contamination, the log produced should be highly accurate.

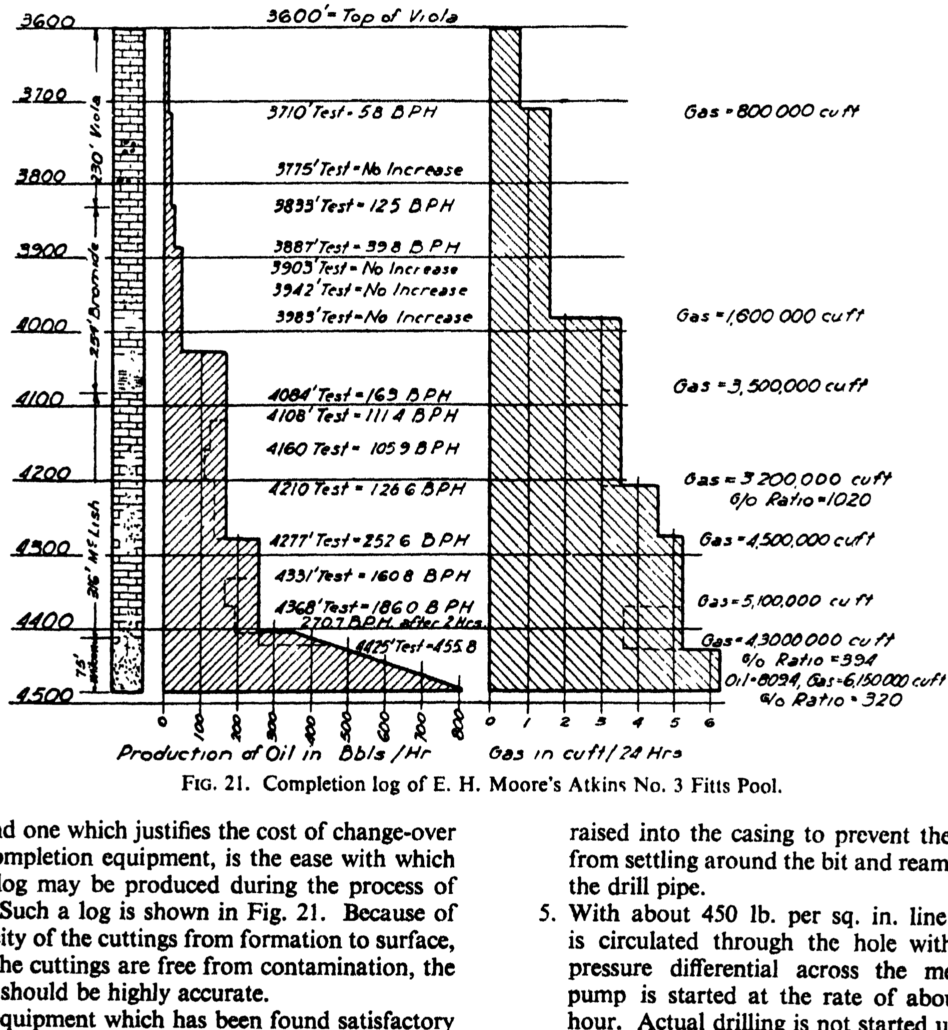


FIG. 21. Completion log of E. H. Moore's Atkins No. 3 Fitts Pool.

A type of equipment which has been found satisfactory in the above fields is the Otis Drilling Head (Fig. 22). This equipment has been found effective for drilling or completing under blow-out pressures up to 1,500 lb. per sq. in. A typical flow diagram for pressure drilling is shown in Fig. 23.

This type of control equipment has been found to be quite satisfactory in that only a short time is required for rigging up, and in that it permits the use of ordinary outside-coupled drill stem and the customary square kelly joint.

For greater clarity the steps involved in pressure completion in Oklahoma City are herewith presented.

1. All pressure equipment is installed after the oil string has been run and while operators are waiting for cement to set.
2. A 4-in. meter loop with a 2½-in. orifice plate is set visible to the driller. A 10×4×10-in. boiler feed pump is used to pump oil into the hole. The regular mud pump cannot be run slowly enough without overloading the hole. Both the oil and gas are pumped into the bottom of the standpipe.
3. The cement plug is drilled with mud. The mud is displaced with water and the water is gas-lifted from the hole by stages.
4. It is very essential that the oil pump and the gas meter are visible to the driller so that in case the hole is loaded or the bit plugged the drill pipe can be raised into the casing to prevent the sand cuttings from settling around the bit and reamer and sticking the drill pipe.
5. With about 450 lb. per sq. in. line pressure, gas is circulated through the hole with about 20-in. pressure differential across the meter. The oil pump is started at the rate of about 25 bbl. per hour. Actual drilling is not started until oil returns are noticed.
6. Two to three points of weight are used in drilling with a retarded motion of the rotary.
7. It is common practice, if the sand is soft and drilling is rapid, to raise the drill pipe off bottom and allow the gas and oil to clean all the cuttings from the hole after each 5-ft. interval of drilling. This is merely a precaution for greater safety.
8. Gauges are taken at the battery every 15 or 30 min. and compared to the input oil to determine the rate of production for every foot drilled. Likewise the input and vented gas is metered to find the gas production.
9. Samples of cutting are caught every 3 ft. These cuttings are very fine since the oil allows every minute

particle to settle out. These uncontaminated cuttings make it easily possible for the geologist to recognize and correlate them.

10. To make a connexion the Guiberson oil-saver is made up. The Rex quick flange on the Otis square kelly drilling-head is broken and the drill pipe pulled up. The Guiberson is constructed so that a tool-joint can be pulled through it with a complete shut-off. The square kelly packer stays on the kelly at all times.
11. The well is allowed to flow when a trip is being made. If the well is producing as much as 30 bbl. of oil per hour, the oil pump may be shut down, but under no condition, except while making a connexion, must the input gas be shut off.
12. The blow-out preventer is used only when the oil-saver rubbers are to be changed.
13. There is enough room between the master gate and the oil-saver to allow the master gate to close when the reamer and bit are pulled up against the oil-saver.
14. A choke (Fig. 24) operates as a further point of control on the discharge line.

Pressure completion has passed the experimental stage and the successes achieved for various areas warrant the recommendation that pressure completion, where wells are drilled with rotary, could profitably be applied in all instances. One operator, who has completed numerous wells by this method, states that geological information alone is worth more than the change-over cost for drilling under pressure. In addition to this advantage, the well may start off on its producing career without the handicap of a partially sealed sand face. The potentials should be greater and the energy within the formation should have an opportunity to work more effectively to bring oil to the bore hole.

Casing under Pressure. Where abnormal pressures exist the hazards of running casing are even greater than those

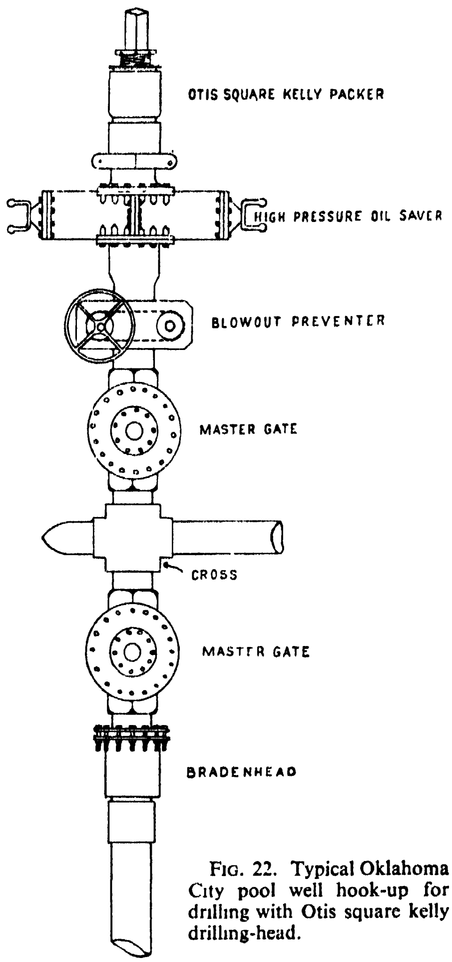


FIG. 22. Typical Oklahoma City pool well hook-up for drilling with Otis square kelly drilling-head.

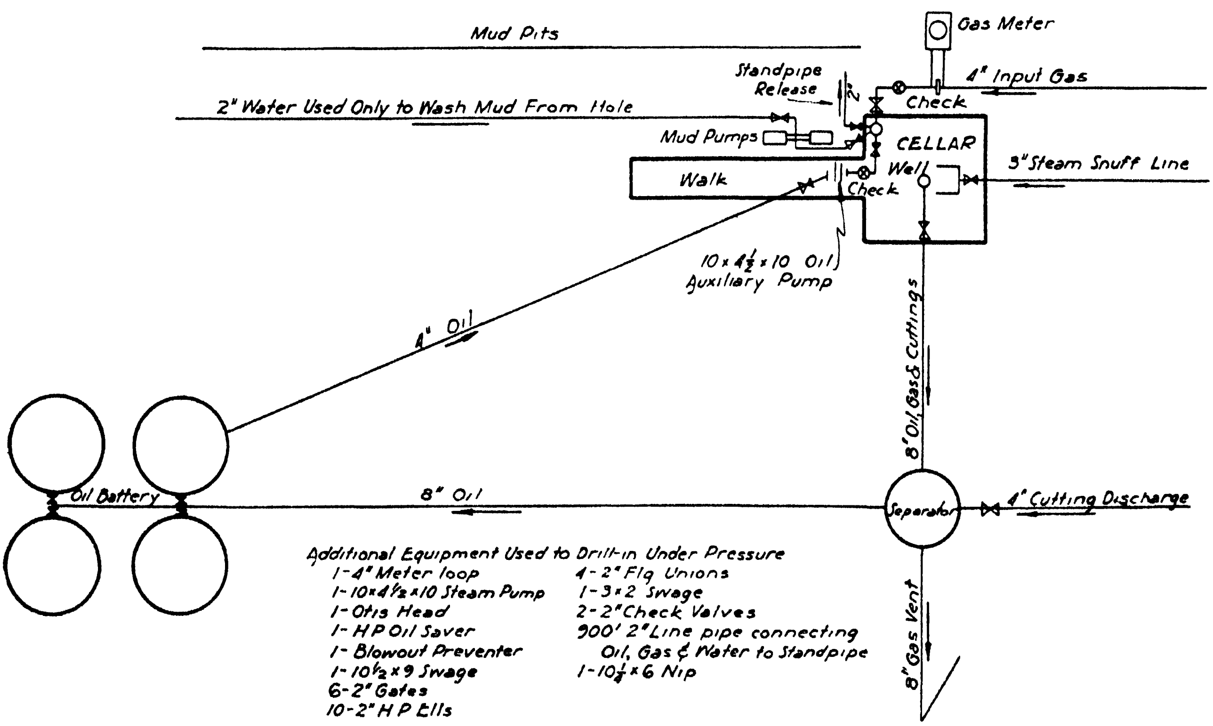


FIG. 23. Typical flow diagram for pressure drilling in Oklahoma City pool.

of drilling. The casing operation being somewhat slower than running a string of drill pipe gives added time for the phenomenon of gas-cutting to take place within the hole. Consequently, the best available equipment should be used to ensure the landing of the casing with the well under control. Considering first conditions where the differential pressure as between formation and fluid head may be as great as 1,500 to 2,000 lb. per sq. in., the situation demands a cemented string of casing with pressure-control equipment in place upon this casing at the surface. Fluid discharge from within the casing should be capable of complete regulation by adequate chokes (Fig. 24). Adequate snubbing equipment is also essential. With these necessary features it is the best practice to run on flush-joint drill pipe and expand or set a casing plug in the lower section of the cemented casing which will relieve the upper portion of the cemented string from all pressure from the formation. The Hydril non-retrievable casing plug and carrier is shown in Fig. 25.

drilling time and 1 to 2 days for rigging up. Here the average pay-roll time amounts to 23 instead of 28 days, and the rigging up accounts for only 9% of the shorter time.

This phase of development work averages the greatest saving in the unitized pool where one company is responsible for all development work. This will be obvious when it is remembered that it is only necessary to provide one system of roads laid out according to a definite plan, one system of water-lines with no duplications, one system of fuel-lines, one transportation department, and one warehouse. If under this set-up adequate plans are worked out, drilling may proceed in an orderly manner without causing unusual peak demands upon the warehousing, transporting, supervisory, and labour departments. If this lay-out is functioning as it should, rotary rigs will be standardized in so far as it is practicable; interchangeable rig parts will be numbered and stored accordingly in the warehouse, and parts will be moved to location according to a want-list

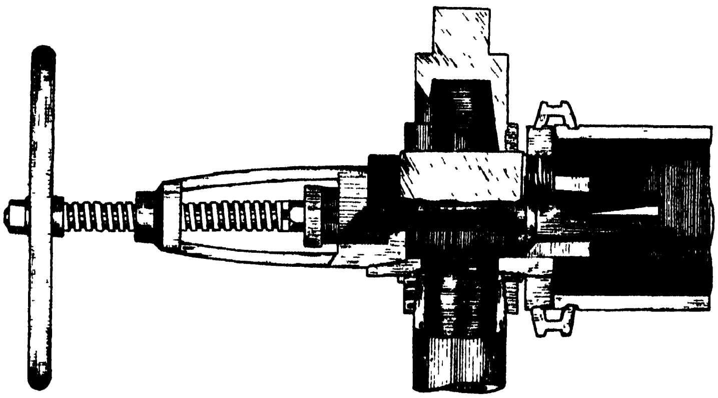


FIG. 24.

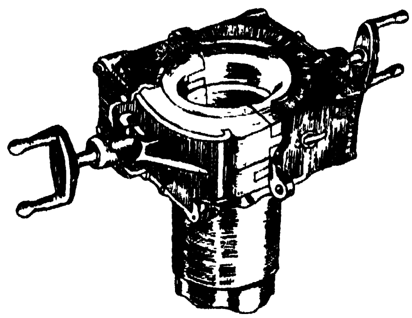


FIG. 26. Guiberson casing oil-saver.

For less severe conditions it is possible to make use of a casing oil-saver for landing casing with the well under control. Fig. 26 shows a Guiberson casing oil-saver used for this purpose. The casing which is to be run through this oil-saver is fitted with a back-pressure float collar or guide plug and forced through the oil-saver. Any flow from the well is diverted through the vent in the adapter. For low pressures this method is satisfactory and requires no change-over, except for snubbing gear, which is very probably in place if the well was drilled under pressure.

Dismantling, Transporting, and Rigging Up Rotary Equipment

In 1931 a canvass of contractors operating in the Oklahoma City field was made in order to obtain plans and specifications for dismantling, transporting, and rigging up rotary equipment. It was surprising to learn that not a single contractor in the field had any such plans. The following illustration will serve to present a quantitative measurement of the desirability for well-conceived plans outlining this phase of development work. In an area in Oklahoma where wells to-day are being drilled to a depth of 4,000 ft., the drilling time required is on the average 21 days. The rigging-up time where equipment is unloaded in a heap and later sorted out, then assembled without any definite plans, amounts to 7 days on the average. Here 25% of the time consumed in completing these shallow wells is chargeable to rigging up. On the other hand, unitized equipment, dismantled, transported, and rigged up according to a definite plan consumes 21 days for

furnished to the warehouse from each location as work progresses at that location. In one Texas pool where the above plan was initiated, four trucks were adequate to keep equipment moving from warehouse or old location to new locations in process of rigging up, and this without any delay in the process of rigging up. The engineer responsible for this information stated that the four trucks under the planned programme served a number of wells which under ordinary practices would have required the services of at least 12 trucks. Furthermore, the material was delivered on location as needed and disposed of without the necessity of rehandling. The rigging-up time was shortened by more than 40%.

The essential features of one programme are [14, 1933]: (1) A careful development of an average floor plan for rig lay-out as shown in Fig. 27. It is to be understood that this plan was designed with the idea of making use of company-owned equipment available in that area. (2) Standardization of the equipment, so far as was practicable, for the purpose of securing at the earliest possible time a number of rigs which conform to the plans and specifications and make for greater interchangeability of parts. (3) The development of plans and instructions covering the steps of dismantling, transporting, disposition, and rigging up for average conditions. Fig. 28 is the plan adopted for disposition of the parts.

Considered concurrently with the development of these plans and specifications a great deal of thought was expended in revamping equipment to make it more portable. Sub-structures eliminated the necessity for digging cellars.

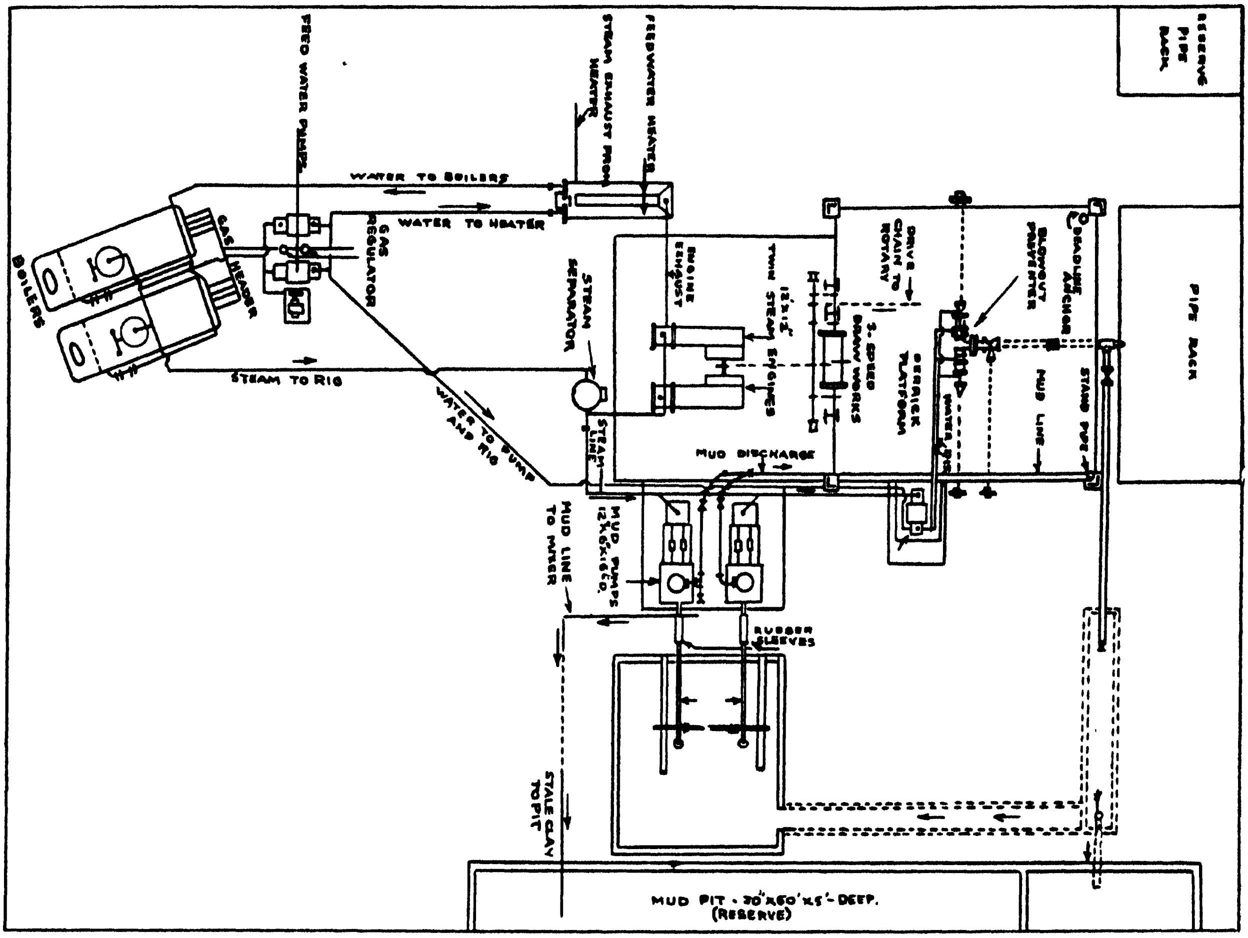

WATER TO BOILERS
WATER TO HEATER
STEAM TO RIG
MUD DISCHARGE
MUD PIT - 30'x60'x5'-DEEP.
(RESERVE)

FIG. 27.

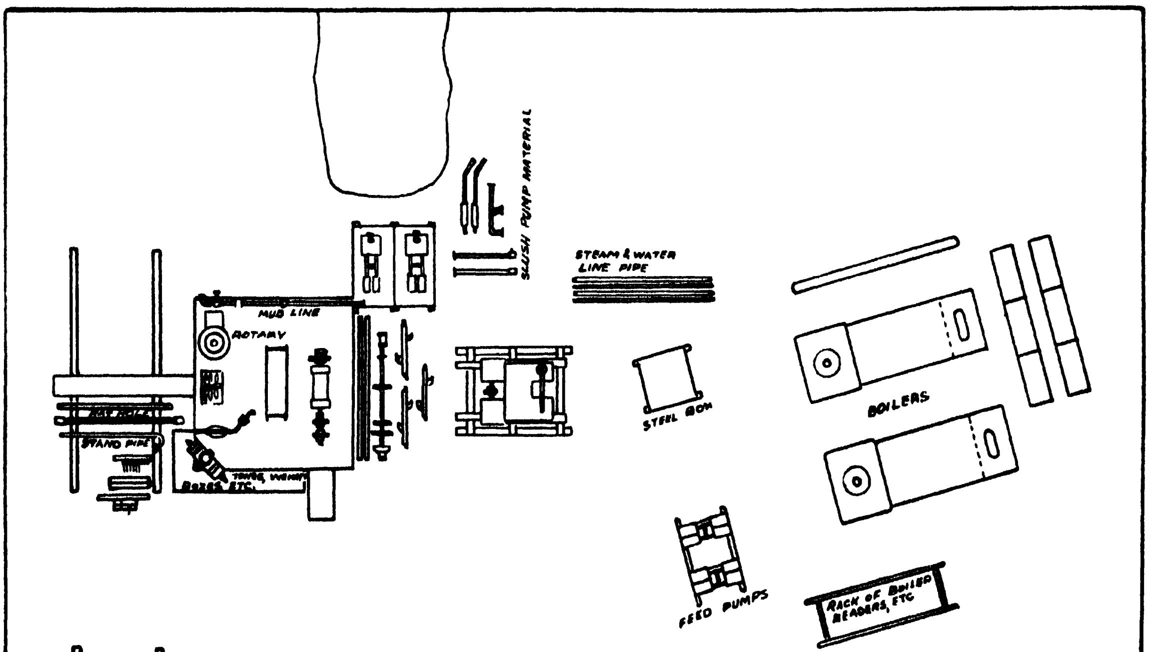

SLUSH PUMP MATERIAL
STEAM & WATER
LINE PIPE
MUD LINE
ROTARY
STAND PIPE
BOXES, ETC.
STEEL BOX
BOILERS
FEED PUMPS
RACK OF BOILER
HEADERS, ETC
CASING
RACK
CHAIN GUARDS
BRACES
ENGINE PLATFORM

FIG. 28.

Structural steel engine foundations which could be skidded to the next location as a unit were designed. The pump hook-up was simplified. The entire manifold, mud-line, and standpipe were designed to be moved in five pieces, all of which have flanged connexions. A special skid-type draw-works was used, and in some instances the older draw-works were converted into unit-type draw-works on skids. Many other changes in equipment to simplify the operations of dismantling, transporting, and rigging up were initiated.

Fig. 29 pictures graphically the progress which was made in reducing the time required for this phase of the work during the year 1932–3.

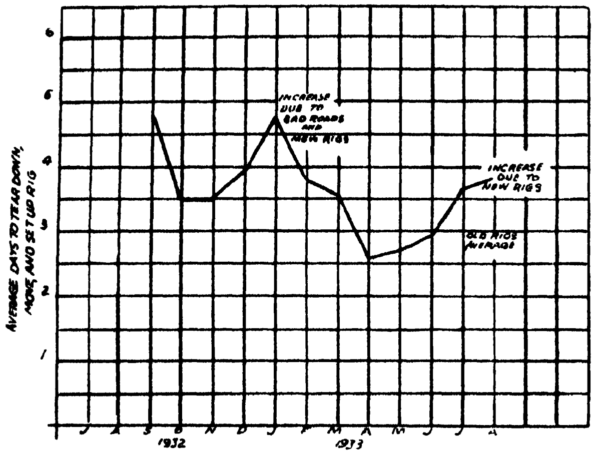


FIG. 29.

Selection of the Proper Type of Rotary Equipment

A great deal may be accomplished in the way of reducing drilling costs by selecting a rotary rig of the proper type to meet the depth and formation conditions in question. The truth of this statement was illustrated when heavy-duty rigs were transported from Oklahoma City to East Texas for drilling at 3,700 ft. Almost as much time was consumed in dismantling, moving, and assembling these oversize rigs as was required in the actual drilling of the well. Conversely, it is true that the rig selected should be of sufficient capacity. Rotary rigs which functioned satisfactorily in drilling 4,200-ft. wells in the Seminole area required nearly twice the time for drilling wells in Oklahoma City as did the heaviest rotary rigs.

For difficult deep drilling the large steam-driven rig continues to be the popular choice. While it is true that a saving in fuel and water costs might be effected by the use of prime movers other than steam engines, it is equally true that for most newly developed fields there is seldom a cash market for available gas, and the price of gas consumed in the boilers at steam-drilling rigs is largely one of book values. The steam rig continues to be the most flexible prime mover; the one best understood by drilling crews; and the one which will withstand the greatest degree of abuse.

For wild-catting purposes, where it is relatively certain that the depth will exceed 4,000 ft., although the final depth is unknown, it is advisable to select equipment having capacities in excess of anticipated needs if for no other reason than that it may be decided to drill deeper to secure geological information for the area.

In wild-cat areas it is very possible that fuel and boiler feed-water supplies may constitute a real problem. These problems may be minimized by selecting Diesel electric rigs; heavy-duty gasoline rigs; alternating-current electric rigs, where power is available; Diesel rigs driving through countershafts, or direct-drive reversible Diesels. These have passed through the experimental stage, and for most makes there is little question concerning their ability to function.

There are other areas where drilling will not exceed 3,500 or 4,000 ft. For these conditions a variety of skid-mounted and truck-mounted portable rigs can be had. The advantages to be gained by a selection of this type of equipment for these shallow depths are:

1. A drastic reduction in cost of transporting, assembling, and dismantling.
2. Reduced depreciation.
3. Lower capital investment.

For certain areas special formation conditions may demand that a part of the hole be drilled with cable tools or that the well be drilled into the producing sand with cable tools in order to avoid the sealing effect occasioned by drilling-in with rotary muds. For the above conditions operators and equipment makers have done much within the past 2 years in developing successful convertible rigs requiring a minimum of accessory parts and a very low change-over time.

Of the large steam-driven rigs, capable of drilling to depths greater than 2 miles, there are many assemblies of the conventional type in which the separate units are chosen according to the contractor's preference as to prime movers, draw-works, boilers, mud pumps, rotaries, &c.

An entirely new departure in the design of heavy-duty rotary drilling equipment capable of reaching depths of from 10,000 to 12,000 ft., is the Turney rig [10]. Designed and built primarily for the use of a drilling contractor in the Gulf Coast area, this rig is well adapted for use in regions where boiler feed water and fuel are scarce or transportation for these items offers difficulties. A rig of this type is particularly suitable for drilling on locations in the shallow bays and marshes along the coast of Texas and Louisiana, where rigs must be set up on mats and piling above water or located on submersible drilling barges.

Figs. 30 and 31 give a clear conception of the constructional details of this exceptionally new design in drilling equipment.

A new Diesel electric rig is illustrated in Fig. 32, with complete rig lay-out shown in Fig. 33.

Of the several truck-mounted rigs available, the one illustrated in Fig. 34 has at the present time successfully completed two wells to a depth of 4,000 ft. The total weight of the drilling rig exclusive of the rotary table is about 42,000 lb. Rigging-up time is reduced to 1 day or less. The truck and an independent motor, each developing 125 h.p., 11,800 r.p.m., and equipped for natural-gas or fuel carburation, constitute the prime movers used with this equipment. The only jaw clutch used in the assembly is for engaging the truck motor-power take-off. Otherwise, the rig is completely equipped with friction clutches, which fact is responsible for securing 4,000 ft. capacity with this light equipment.

Fig. 35 illustrates a popular type of rig for areas where a scarcity of good boiler feed water offers difficulties in steam-rig operation. These rigs are available for any depth up to 5,000 ft. The unitized draw-works can be had in all variations from those requiring 70 h.p. up to 300 h.p. engines. The prime movers are furnished in sizes up to 300 h.p. in

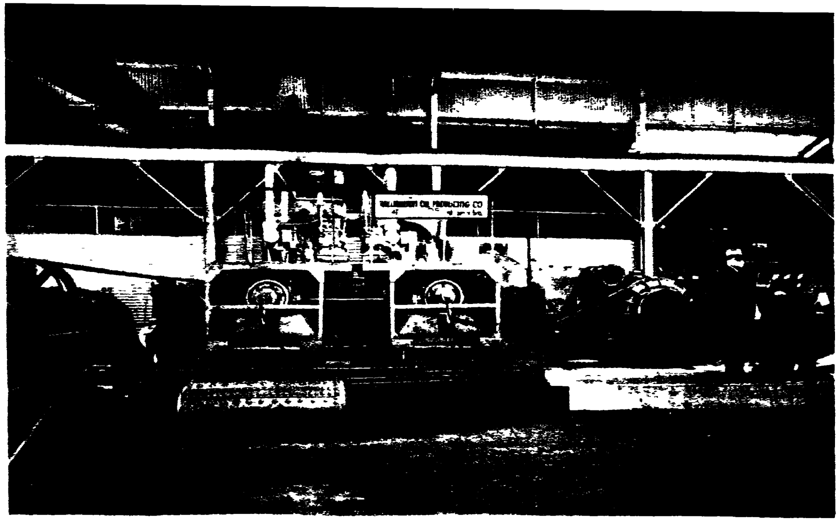


FIG. 30. Survey rotary rig

FIG. 34

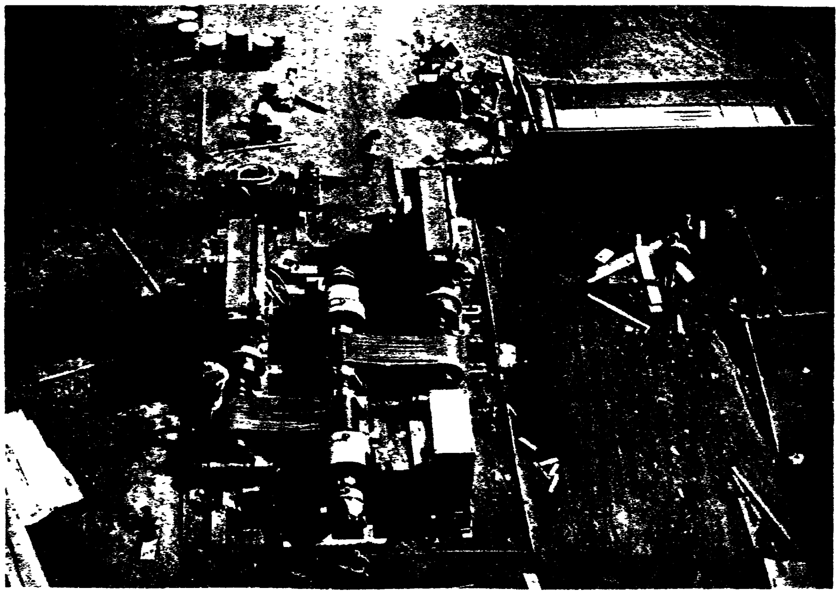


FIG. 32. Diesel electric rig

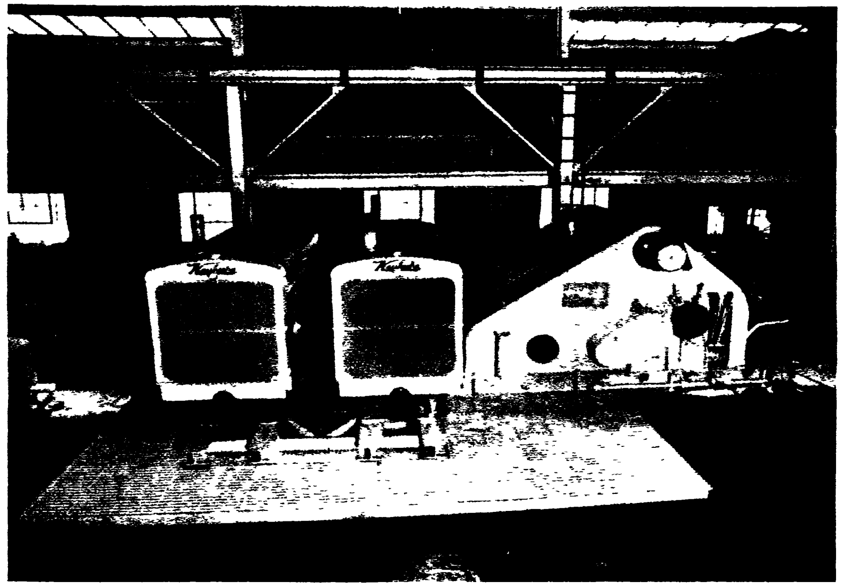
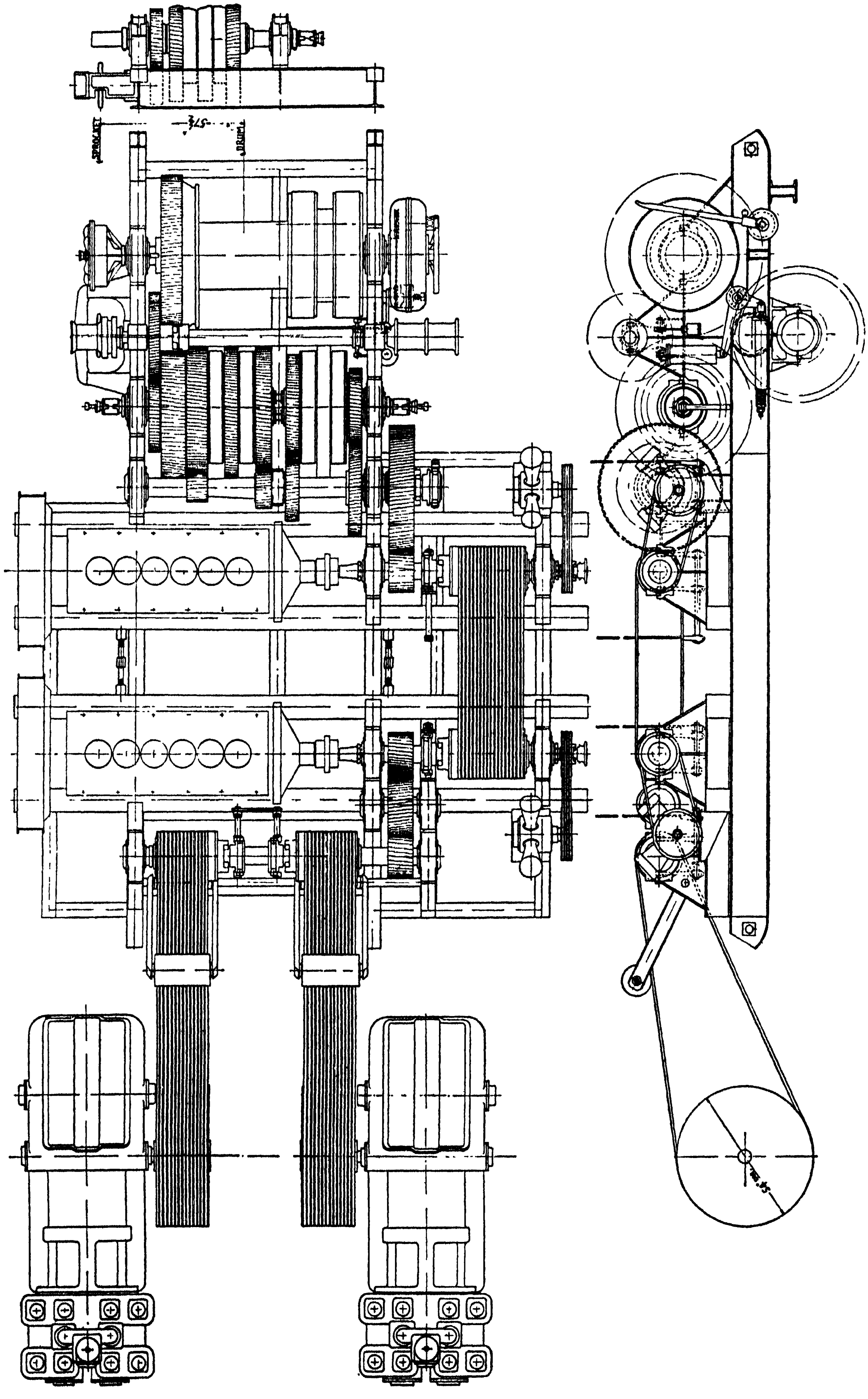
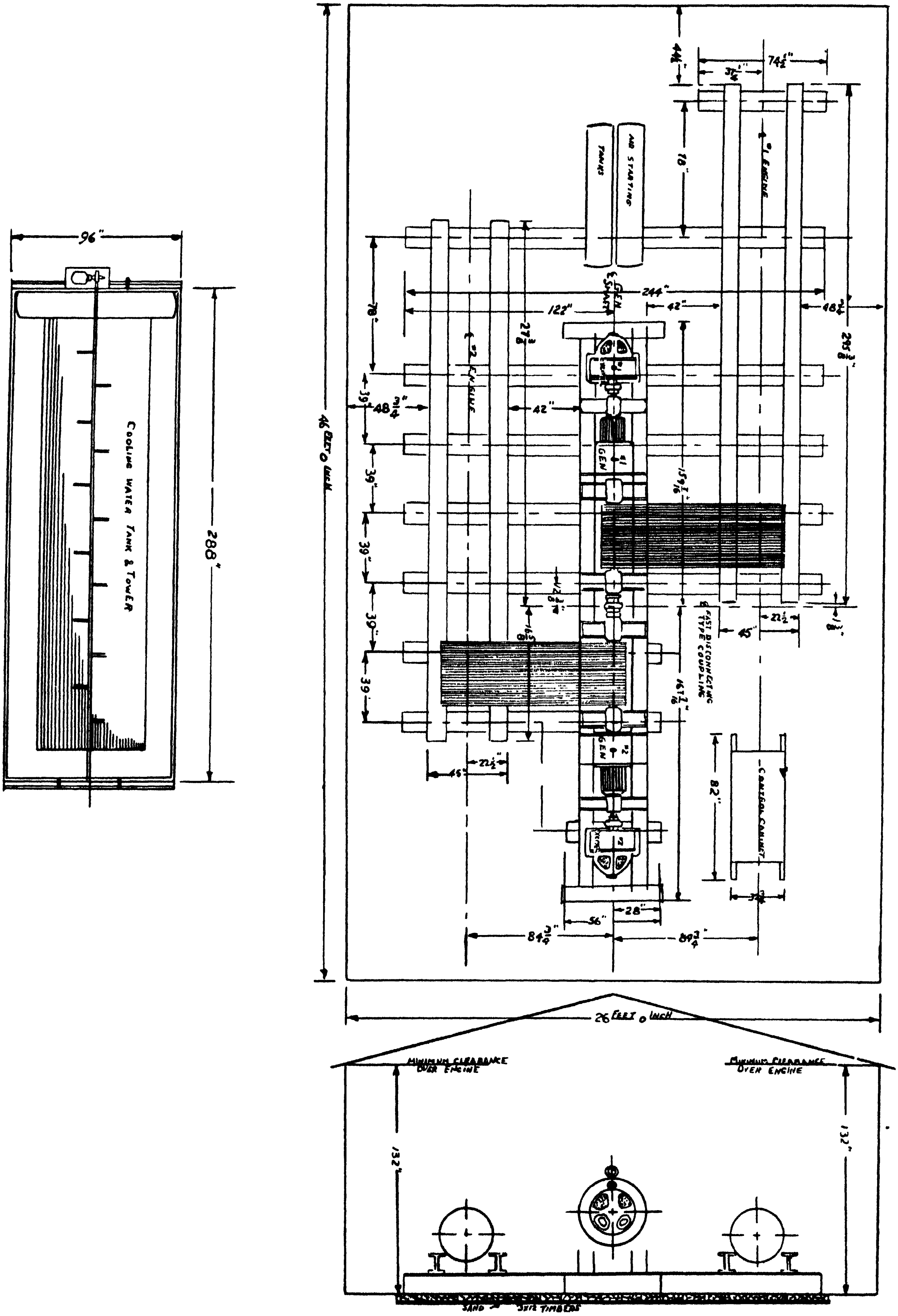


FIG 35



(Turney Drawworks Assembly)

FIG. 31.



96"
288"
COOLING WATER TANK & TOWER
46 FEET 0 INCH
AIR STARTING
TANKS
244"
122"
42"
39"
45"
22½"
56"
28"
82"
CONTROL CABINET
FAST DISCONNECTING TYPE COUPLING
26 FEET 0 INCH
MINIMUM CLEARANCE OVER ENGINE
132"
SAND
3x12 TIMBERS

FIG. 33.

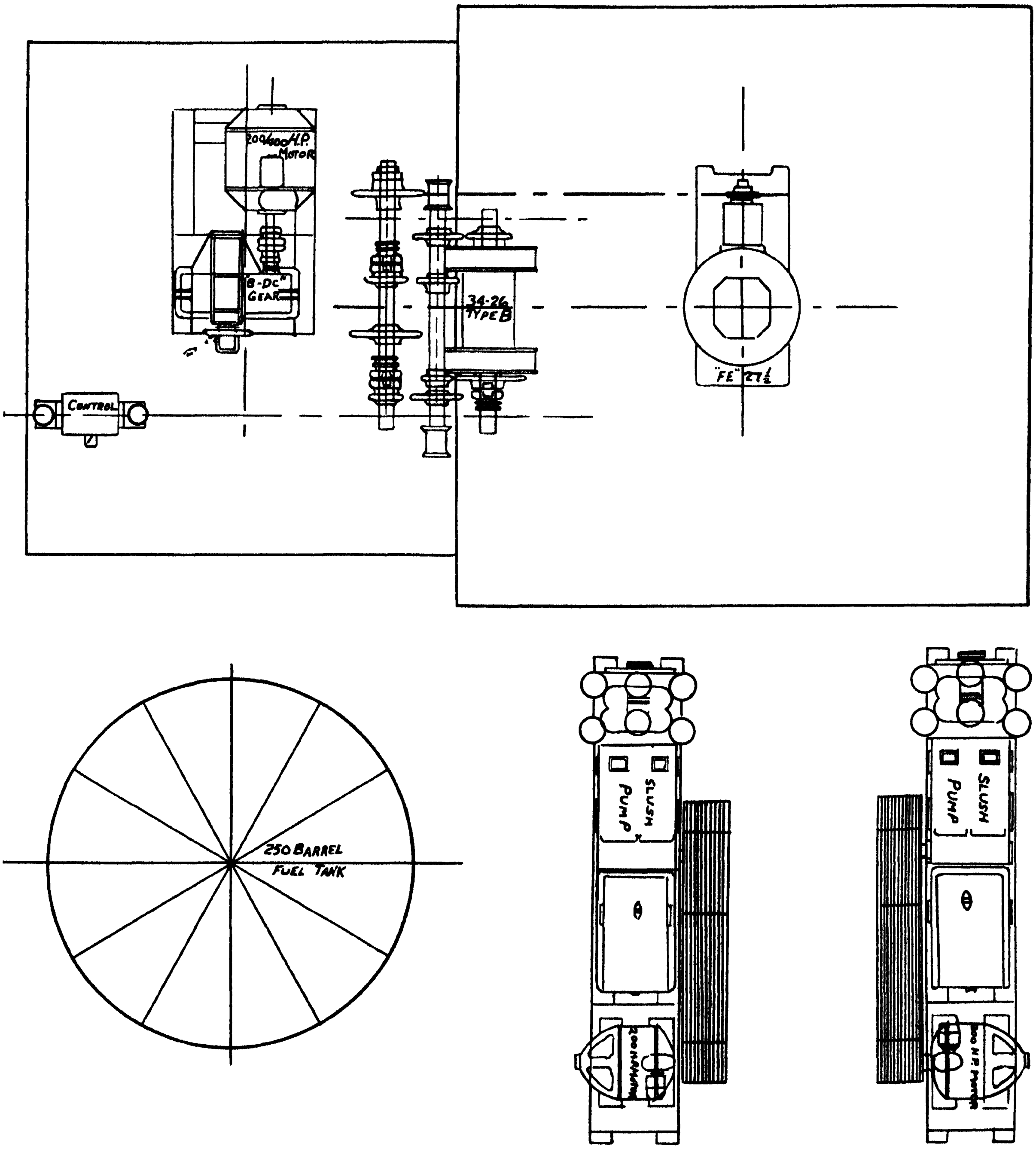

200/600 H.P.
MOTOR
"B-DC"
GEAR
34-26
TYPE B
"FE" 27½
CONTROL
250 BARREL
FUEL TANK
SLUSH
PUMP
SLUSH
PUMP

FIG. 33 (*contd.*).

gas, gasoline, or Hesselman low-compression, spark-ignition, solid-injection oil engines. In all cases provision is made to drive the pump with one engine and the draw-works with the other, permitting both engines to drive to the draw-works when pulling pipe. Either chain or V-belt drive may be had.

A highly successful convertible-type rig is illustrated in plan view (Fig. 36), and in elevation (Fig. 37). The unitized shaft supported by jackpost bearings on an 'A' frame steel jackpost. The upper shaft is equipped with a 132-tooth sprocket keyed to the shaft. The sand reel is set in front of the rotary draw-works and driven off the rotary-drive sprocket. When ready to drill with cable tools the chain between the pump and the rear countershaft is removed from the pump and placed upon a 132-tooth sprocket. The rig is then controlled in the same manner as that described

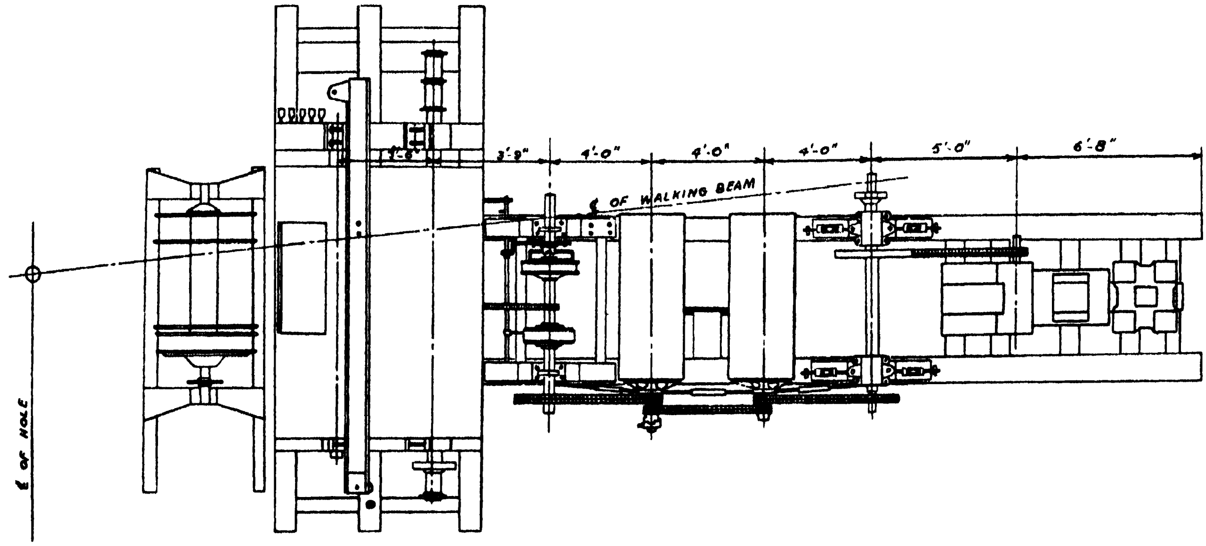


FIG. 36.

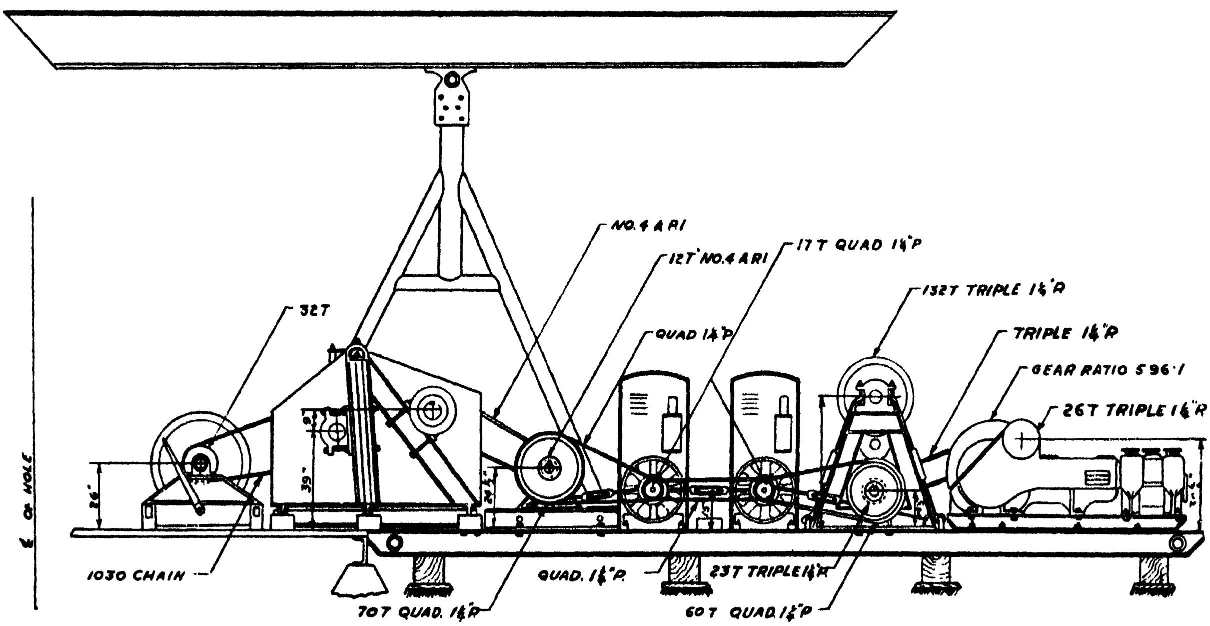


FIG. 37.

draw-works is mounted on one skid, and the reverse clutch, prime movers, crank-shaft assembly, and mud pumps are mounted on another skid. When converting to cable-tool drilling, the lower end of the 'A' frame Sampson post bolts to the power skid, and the upper end bolts to the head-board on top of the draw-works assembly. A 31-ft. regular, 24-in., 110-lb. silicon-steel walking beam is used along with the regular steel pitman equipped with self-alining bearings. The cable-tool unit immediately in front of the mud pump is a regular 5-in. 4-hole band wheel, crank and crank- for rotary drilling except for the fact that normally only one motor is used.

Completion of Rotary-drilled Wells

A description of a best method for completing rotary-drilled wells is not possible in view of the widely varying conditions under which completion must be made. It can be correctly stated that too often completion methods follow established practices instead of choosing the best method for the well in question. The recommendations

which follow are based upon engineering knowledge acquired and proved by the industry within recent years.

Coring should begin some distance above the productive zone and continue until the sand is reached.

A string of casing should be cemented just above the producing sand. Open hole between casing shoe and productive sand will usually promote difficulties during the later life of the well. Cementing casing before drilling into the productive sand is becoming increasingly important with greater depth because of the hazard of sealing with mud or cementing the formation where it is the practice to take full penetration of the sand before cementing the oil string.

Continuous cores should be taken in drilling into the sand, and penetration should stop well above the oil-water contact. It is possible that conservation agencies will in the future limit the amount of penetration within the various fields for the benefit of all concerned. Drilling into the oil sand with oil as a circulating fluid has been shown to be a better practice for many fields than drilling in with mud fluid. Drilling into the oil sand with pressure equipment is an even better practice which has passed the experimental stage. The flow from the formation while penetration is being taken ensures a clean sand face and an accurate log of the producing formation as well as the production.

A new development in shooting producing sands makes use of sand tamping for stemming the shot [13, 1935]. This method permits shooting immediately below the casing shoe without damaging the casing or casing seat. A new feature in well-shooting is the use of a composition nitroglycerine shell which is reduced to minute fragments as a result of the explosion. This eliminates the necessity for drilling up considerable quantities of tin which was an objectionable feature where metal containers were used.

If wells are tubed at the time of completion, the hazard and expense of running tubing under pressure is avoided. It is generally true that where the well is tubed, especially if the tubing is set low in the well, gas-oil ratios may be kept at values lower than where the well is produced through casing. Tubing makes it possible to maintain a more satisfactory balance between cross-sectional area of the flow tube and the volume of fluid available at the bottom of the bore hole for a longer period of time than where production is taken through the casing. Equipping a well with tubing at the time of completion makes it possible to use a simplified and inexpensive Christmas-tree hook-up instead of the oversize hook-up, which is more than 5 times as expensive as the former.

Finally, the hazardous and wasteful practice of permitting a well to flow over the derrick should be abandoned. However, the more satisfactory method of completing through the separator requires that the more advanced practice of washing the well or drilling in with oil be used.

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SPECIAL ALLOYS FOR DRILLING BITS

By H. W. FLETCHER, M.E., A.S.M.E., A.I.M.M.E.

Hughes Tool Co.

THE selection of material for the construction of tools used in drilling deep wells, and more especially oil-wells, is subject to somewhat less restriction as to cost than is ordinarily encountered in most engineering applications. Space limitations are definitely defined by the diameter of the hole to be drilled. The amount of material that can be employed is to a large extent fixed by geometrical rather than mechanical considerations. Furthermore, the cost of pulling the drill pipe from the hole and replacing it in order to renew worn bit parts is so high that even a small improvement in performance justifies what might otherwise seem a disproportionate increase in the cost of the materials employed. Not only is this the case, but every precaution must be taken to ensure against breakage and loss of parts in the hole, since there is always the hazard of junking a well nearing the point of completion, with a consequent money loss far in excess of the value of all the tools employed in the drilling of that well.

Following the inception of the rotary process, the fishtail bit or some modification (Fig. 1) was universally used for drilling not only the unconsolidated sands and clays, but also the harder limestones, anhydrite and sandrocks, and on the average with marked success in spite of the fact that these bits made of 'tool steel' containing approximately 65 to 90 points of carbon, dressed to shape and heat treated in the forge by quenching the cutting edges in water and drawing back to the desired colour temperature, exhibited a hardness somewhat less than the hardness of quartz (7 on Moh's scale). The inevitable result was that progress was slow in the more abrasive and harder formations, the wear off the bit blade frequently exceeding, by several times, the footage drilled. No really satisfactory solution of this difficulty appeared until about 1909, when the introduction of toothed roller cutters provided a tool in which removal of the formation by scraping was a secondary and minor action, and the principal cutting was accomplished by chipping.

Roller rock bits, used mainly in those formations which proved too hard and abrasive for satisfactory performance of the fishtail bit, have developed mainly along two lines: the first type consisting of two or more cone-shaped cutters as illustrated by Figs. 2 and 3; and the second by the so-called cross-roller type shown in Fig. 4. While scraping in these tools is subordinate to the chipping and crushing action to a very considerable degree, abrasion remained a problem of major importance, as the dulling of the cutter teeth occurred mainly through this action and resulted in a sharp decrease in rate of drilling and reduced life. It was obvious that the highest possible hardness must be maintained on the tooth surfaces, but at the same time the unusually heavy structural loads encountered required a tough and shock-resisting combination. These conflicting requirements could hardly be satisfied by any homogeneous material, and accordingly a low carbon chrome-nickel steel of carburizing grade, corresponding to S.A.E. 3,115, was adopted with a heat treatment designed to regulate properly the maximum percentage of carbon in the rather sharp tooth crests and to develop the maximum toughness in the core in the hope that if under extreme conditions case cracks should develop, the tough core would hold the parts together until they could be withdrawn from the well. That this combination proved to be an effective answer to the problem is best indicated by the widespread use of bits of this type in areas where rotary drilling predominates, many wells in certain districts being completed with rock bits from top to bottom.

During this same period a type of bit intermediate between the fishtail and rock bit, and carrying at the lower end two or more disk-shaped cutters (Fig. 5), was introduced with more or less success, the theory being that more inches of cutting surface could be provided in a hole of a given diameter than was the case with the fishtail, and that consequently economies could be secured through improved bit performance. Again it was found necessary to use a carburizing grade of material, and the majority of the cutters employed were made of a steel comparable with the S.A.E. 3,115 analysis and heat treated in general after the practice established for rock bits.

The fact was soon recognized that a certain degree of 'red hardness' was desirable for the scraping type of bits, as in spite of the cooling effect of the circulated mud, the heat of friction would in certain formations draw the temper of the cutting edges and soften the metal to a point where loss by abrasion became excessive. This action usually resulted in wearing the bit to a 'diamond point' which would be expected, as the heating would be greatest at the outer diameter of the cutting edges. A few attempts were made to use high-speed steel for this purpose, but the first material used in quantity which offered 'red hardness' and at the same time some increase in scratch hardness, was stellite, an alloy of cobalt, tungsten, and chromium, with a hardness of about 7 on Moh's scale.

Early in 1927 a process was developed for producing tungsten carbide on a commercial scale. This material has a mineral hardness in excess of 9 on Moh's scale, and in its earliest form consisted of minute tungsten carbide particles sintered with some tougher matrix material. This process involved considerable technical skill, and this, in conjunction with control of the market through patents, made the initial price exceedingly high, and limited the general use for drill-bit purposes in spite of the consideration outlined in the first paragraph. During that same year, however, processes were developed for producing fused tungsten carbide at a considerably reduced price, and rendered available a material which could be applied to the tools with either the acetylene or atomic hydrogen torches under conditions of commercial production. Tungsten carbide is manufactured by intimately mixing a very pure grade of metallic tungsten powder with such an amount of powdered carbon as will produce a mixture of the alloys WC and W_2C containing approximately 4% carbon. This mixture is then heated in a graphite crucible, either by direct arc or by resistance heating of the crucible itself to a temperature of approximately 6,000° F., at which temperature the carbon and tungsten combine to form the carbides as noted. This melt is then cast into ingot moulds

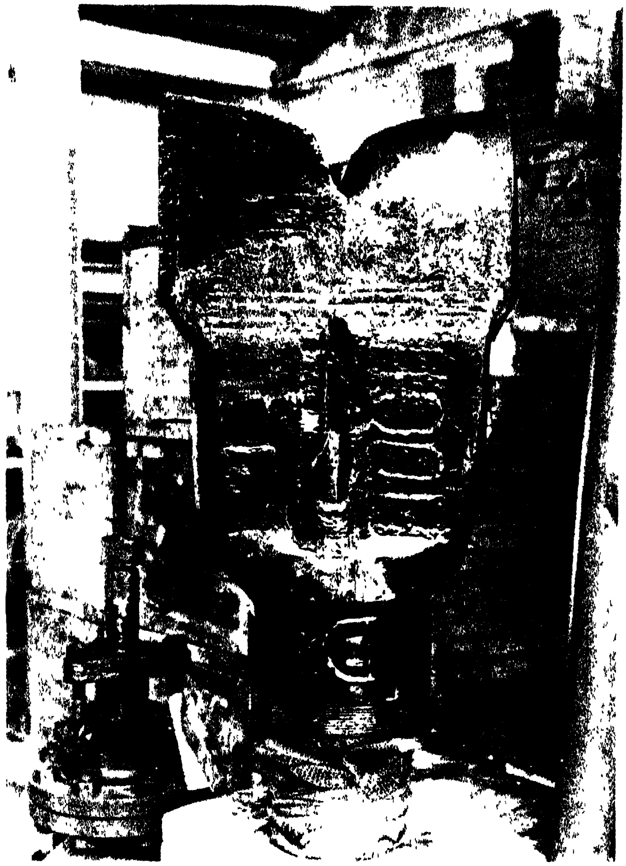

Fig. 1

Fig. 2

Fig. 3

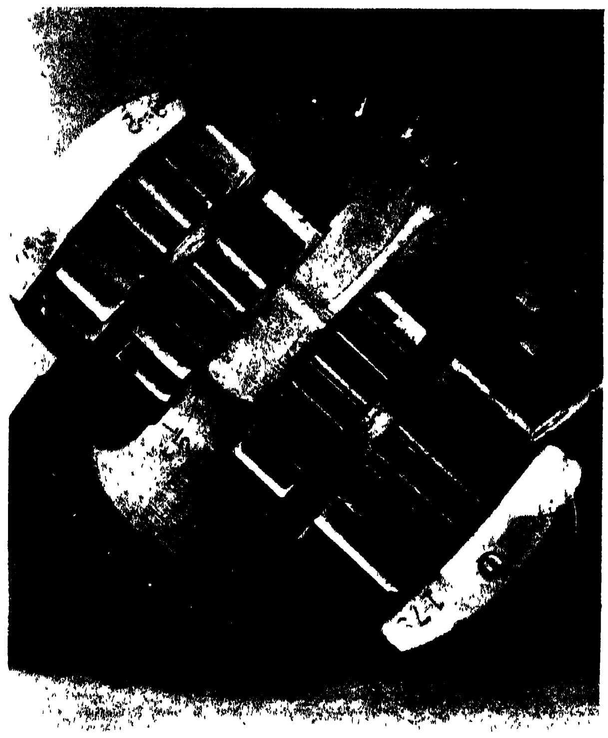

Fig. 4

Fig. 5

Fig. 6

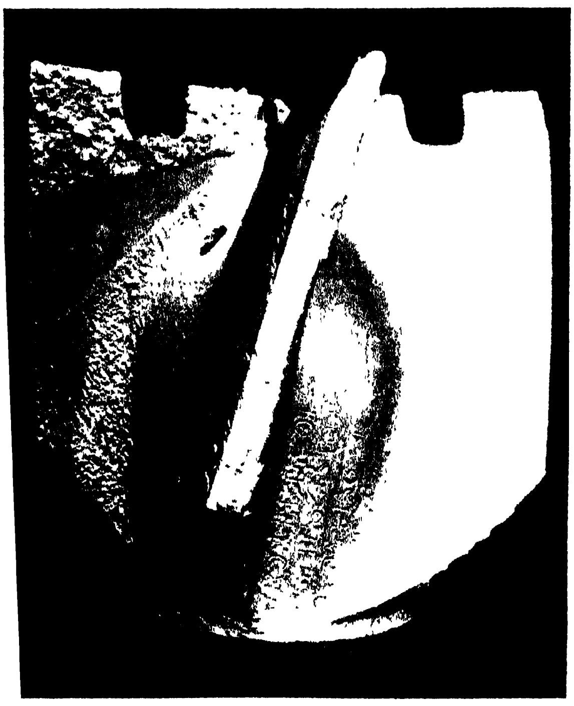

Fig. 7

Fig. 8

of various sizes and shapes, and these ingots are then welded to the cutting edges of the bit as 'inserts', or are crushed and graded and applied as a rather coarse powder with iron or some other alloy as a binder. The hardness of the resultant product depends to a considerable degree on the amount of alloying that takes place during application; if too much puddling occurs, the hardness actually decreases as the tungsten carbide tends to dissolve in molten iron, and while there is a considerable gain in toughness, the sharp reduction in hardness considerably reduces the resistance to abrasion. Still another process has been devised for securing high surface hardness, in which the simple mixture of tungsten and carbon powder is applied to the surfaces of the work and the tungsten carbide made in place by reduction under a carbon arc.

Fused tungsten carbide may be produced commercially either in a small arc furnace or by a 'crucible process' wherein the heat is most conveniently developed by passing large, low-voltage currents through the crucible itself. In either case the crucible is formed of graphite, and a mixture of tungsten powder and carbon in the desired amounts is raised to a temperature somewhat in excess of 6,000° F. A very pure grade of tungsten powder is required, as the presence of oxides or of occluded hydrogen generates large quantities of gas which make the heat wild, causing a loss of metal and tending to form blow holes in the finished product.

In the arc process the condition of the melt can be observed through suitable dark glasses, and when, in the opinion of the operator, the reactions have been completed the crucible is removed from the furnace with tongs and the molten tungsten carbide poured into ingot moulds, which may be of graphite or water-cooled copper. In the case of the resistance furnace, direct observation of the melt, of course, is impossible, and reliance is placed mainly on cycle control to secure uniform results.

Approximately 4% carbon is mixed with the tungsten powder, and the resultant alloy consists of a mixture of WC and W_2C. It is very undesirable to have an excess of carbon in the melt, since it will appear as graphite and the product will be non-uniform and brittle. Rapid cooling improves the quality of the material, as a fine crystal structure is thereby maintained and porosity due to dissolved gas reduced. For this reason centrifugal casting of ingots has proved useful in connexion with this product.

The ingots are either run through a crusher and sized on screens to separate the particles into grain size suitable for various purposes, or in some cases the ingots are cast in small slugs which may be used directly for application on cutting edges of bits.

A great deal of work has been done in an effort to increase the toughness of tungsten carbide without too greatly lowering its hardness. While the material is very strong it is also exceedingly brittle; the addition of cobalt, chromium, and other alloying elements has a marked effect in increasing the toughness of this material, but at the same time results in a sharp reduction in hardness with a corresponding reduction in resistance to abrasion. The character of the service for which the material is intended determines to a considerable degree whether or not the carbides should be used alone or with some toughening addition; loss by chipping may in some instances result in a more rapid destruction of the cutting edge than would result from abrasion on a somewhat less hard but tougher alloy.

Where maximum density of structure is required, it has been found desirable to produce tungsten carbide in two melting operations, the first to combine the tungsten and carbon and freeing the melt to a considerable degree from gas. The ingots resulting from this first melting are then crushed and the particles are remelted, with the result that a more uniform composition throughout the mass is secured and the last traces of visible gas eliminated. In each case care must be exercised to avoid holding the molten metal too long in the crucible, as rapid absorption of carbon occurs at the high temperatures involved and an excess of carbon in the melt is apt to result in a coarse-grained and weak material with appreciable quantities of free graphite present.

The scratch hardness of tungsten carbide lies somewhere between 9 and 9·5 on Moh's scale, with quartz at 7. The Brinell hardness is approximately 2,000, and the compressive strength in the neighbourhood of 200,000 lb. per sq. in. Bits faced with this material will make from 5 to 10 times as much hole as ordinary tool-steel bits, resulting in marked economies in the drilling of deep wells.

Availability of material of this nature considerably expanded the field of the scraping bit, as it was no longer necessary to rely on the resistance to abrasion which could be secured by simple hardening of the steel alone. One fundamental advantage shown by the form of the fishtail bit was that when the bit was dulled excessively it could be reheated in a field shop, the blade thinned out under a hammer, when it became a simple matter to re-form the cutting edges. The introduction of acetylene and electric welding equipment into field operations made it possible to build up worn bits to something like their original shape and avoided the necessity for forging operations, with the further advantage that bits of irregular shape which were unsuited to forging could be built up quite as easily as the plain fishtail. Many fishtails were hard faced as indicated in Fig. 6 and with good success; in addition a large variety of bit forms appeared carrying more than two cutting edges. These bits were unsuitable for reforging, but provided more wearing surface per run, with the idea that a lowering of drilling costs would result (Fig. 7).

While the hardness of tungsten carbide is such that reasonably satisfactory resistance to abrasion results, the material is exceedingly brittle and considerable loss by chipping may occur when rough running is encountered. The various methods of applying this hard facing to scraping bits have resulted largely from an attempt to maintain the necessary keen cutting edge as far as possible, and at the same time to protect the rather brittle material from this chipping action. The most general method of application now in vogue consists in the incorporation of small tungsten carbide nuggets in the cutting edge of the tool, overlaid with a tungsten carbide and iron alloy or some other combination less brittle than the carbide itself. These inserts are often so arranged that the bit will 'finger' as illustrated in Fig. 8, as the idea is rather generally accepted that a bit which 'fingers' will show better performance than one which maintains a more or less even cutting edge.

As might be expected, the adaptation of tungsten carbide to the hard facing of roller cutters presented some additional problems over and above those developed in the hard facing of drag bits. The form of teeth required in these roller cutters necessarily results in a somewhat delicate cutting edge, and higher unit loads are encountered, since the bits are used more generally in the harder formations. Furthermore, the application of this material to highly carburized teeth results in severe temperature strains which are apt to cause checking of the case and subsequent failure. Care must be taken that the cutting edges are not

too severely blunted, due to the surface-tension effect of the molten hard facing material as it reaches the cutting edge, and that the stock of the tooth is not actually burned away at the high temperatures required to fuse properly the facing. From a metallurgical point of view, it is rather astounding that any success at all can be realized in such an operation, but with the greatest attention to detail a satisfactory result may be secured. While no doubt the cutting life of all the teeth is extended to a considerable degree, the principal benefit derived from this hard-facing operation lies in the protection of that part of the cutter which must maintain the diameter of the hole. It is, of course, obvious that as a bit wears, the hole produced by that bit reduces in size. It is, fortunately, the case that, on the average, bits drill a hole greater than their own diameter, so that if wear is not too excessive, a new bit can be put on bottom without the necessity of reaming the hole made by the worn bit. On the other hand, the loads handled in deep wells are very large, and if the hole is only slightly tapered, a new bit may be crowded into this undersize portion and seriously damaged before drilling starts. It is undoubtedly true that the hard facing has reduced to a considerable degree the troubles formerly experienced from this factor.

Other hard alloys have been tried to avoid some of the disadvantages of straight tungsten carbide. The addition of cobalt to tungsten carbide will materially toughen the material, though at the expense of considerable reduction in scratch hardness, while a more recent alloy containing chromium boride is rather easier to apply, particularly to roller cutters, and is somewhat less subject to loss by chipping, with nearly as good resistance to abrasion.

The severe service requirements encountered in operating drilling bits in deep wells has thus resulted in the development of the hard-faced fishtail with shank usually of medium carbon steel; the multi-bladed fishtail or 'drag' bit cast rather than forged to shape; and the roller bit with cutters of medium alloy steel, usually a chrome nickel of carburizing grade and hard faced as well as carburized. These improvements have resulted in a marked increase in footage per bit and to a certain extent offset the otherwise greatly increased expense of carrying wells to the relatively great depths now reached which, 10 years ago, would have been considered impracticable.

THE DRILLING AND CONTROL OF HIGH-PRESSURE WELLS

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HIGH pressures are the inevitable concomitant of deep development operations, and the subsurface conditions under which the pressure exists determine the precautions that must be taken to maintain control of a well during drilling and the initial flush-production period.

The maximum pressures to which gas or liquid in an oil-well are subjected will depend upon a static head resulting from the entry of water into the producing formation through an outcrop at the surface or upon the weight of the superincumbent formations. Pressure in itself does not, however, offer many difficulties. The presence of high-pressure gas associated with the oil underground produces hazards which are not normally present when little or no gas accompanies the oil.

The general practice in high-pressure areas in the past was to use mud fluids of high specific gravity to exert a hydrostatic pressure on the formations sufficient to maintain control of the well. In order to obtain drilling muds of sufficiently high specific gravity to control high pressures it is usually necessary to add a weighting material, such as barytes, to the fluid. Conditions may exist which may result in the complete and permanent mudding-off of valuable oil shows, and in highly fissured areas it may be impossible to maintain the hole full of drilling mud. Should high-pressure gas be present in such fissured areas a highly dangerous condition would arise.

Although the mud method of control was not completely eliminated, some mechanical means of control became necessary and pressure drilling became the accepted method.

Pressure-drilling equipment consists essentially of some form of gland fitted to the wellhead through which the drilling tools can be operated. A number of blow-out preventers are available for all types of drilling strings, which enable the drilling strings to be withdrawn from the well under pressure whilst maintaining the necessary back pressure on the well.

The cellar is a matter of considerable importance in pressure-drilling. A more elaborate layout of rig foundations and of cellar construction are necessary than in the case of a normal pressure well, and it is advisable to provide means whereby the crew can escape easily from the cellar in case of trouble and for flooding it with water in case of fire. At the same time, adequate drainage for any oil or water that may collect around the wellhead should be provided. Ample space should also be allowed for erecting the wellhead fittings when the well is ready to produce.

Cellar construction will vary in different areas, but the general practice is for steel sub-structures giving increased strength and immunity from fire.

All wellhead valves should be capable of being operated from a distance, and remote control handles should, therefore, be placed outside the cellar. By this means the well can be shut off or controlled from outside the cellar with a consequent reduction in risk to the drilling crew.

Considerable control can be maintained by the use of weighted fluids to which have been added materials of high specific gravity, such as barytes, iron oxide, or haematite, in those areas where no detrimental effect will result from their use. Ample supplies of mud fluid must, therefore, be available, and where possible it is advisable to arrange the pits in such positions that gravity feed will convey the mud to the slush pumps to permit the suction of the pumps to be flooded at all times.

By the use of these weighted muds a pressure can be exerted on the formation in many cases sufficient to withstand the pressure at the bottom of the hole, and where the mudding off of the producing zone is not to be feared this method of control is efficacious. Certain disadvantages may exist, such as rapid gas cutting of the mud, making it difficult to retain the desired weight, and in this case facilities must be arranged at the flow head to enable mechanical control to operate.

Various items of equipment in addition to the normal rotary equipment are used and chief among these are blow-out preventers, scrubbing gear and clamps, back-pressure valves for the drill pipe, and a kelly cock.

Blow-out preventers may be divided roughly into two groups: (i) those which serve only as a seal against the drilling string whilst drilling is suspended, (ii) and those which permit drilling to be continued when in operation.

Both groups of blow-out preventers take a number of forms but their functions are the same.

In the first group any packer which will close the annular space between the drill pipe and wellhead will act as a blow-out preventer (Fig. 1).

In general blow-out preventers of this group consist of two main parts: (i) the packing head which is screwed to the casing and has an internal bore for receiving, (ii) the packing assembly. The packing head is in position all the time whilst the packing assembly may be suspended in the derrick in close proximity to the drill pipe, so that at the first indication of a blow-out it may be swung into position, locked about the pipe, and lowered into position. The weight of the drill pipe being allowed to rest on the packing assembly squeezes the rubber packing into close contact with the interior of the body and the drill pipe.

Modifications of the various parts exist and mechanical operation is naturally favoured. Thus a number of blow-out preventers working on the principle outlined are available in which manual operation is completely eliminated.

One of these is operated by pressure cylinders which shoot the packing assembly around the pipe, lowering of the pipe forcing the assembly into the sealed position in the body. The packing assembly is automatically retracted from around the pipe and carried back to the open position by releasing the locking dogs, for which operation special wrenches are furnished (Fig. 2).

Another type of blow-out preventer of the first group is of the ram-operated type and can be either manually or pressure operated. The principal operating parts of this blow-out preventer are two rams which are placed opposite each other in the body of the preventer and are capable of rapid closing against the drill pipe. Whether pressure operated or manually operated, complete closing-in of the well is possible provided the correct size packers are used, and pressures up to 6,000 lb. per sq. in. have been successfully held by this preventer.

Blow-out preventers of the first group have been, and will no doubt continue to be, quite satisfactory for drilling in areas of normal pressure, but where higher pressures are encountered it becomes necessary for a positive control to be available, and for this purpose blow-out preventers which will enable drilling, casing, tubing, and pulling to be carried out whilst the well is producing or blowing have been developed.

As in the first group, these second group blow-out preventers will take many forms, but their functions will remain the same irrespective of the method of operation or the shape or size of the preventer.

As for all types of blow-out preventers, their function is to close the annular space between the casing and the drill pipe, but for pressure drilling it should be possible for such control to be maintained whilst the well is being drilled. This calls for a safe, automatic, and instantaneously effective means for preventing blow-outs.

Blow-out preventers for use in pressure drilling may be divided into four general groups:

(*a*) Those which rely upon a series of glands, one above the other, and are capable of being adjusted for wear by tightening nuts or gland rings.

(*b*) Those in which the well-pressure is utilized to move a piston to force a rubber sleeve into a cone-shaped casing and thereby contracting the sleeve on to the drill pipe.

(*c*) Those which make use of hydraulic pressure to force a rubber sleeve against the drill pipe or square kelly.

(*d*) Pressure operated ram type.

Blow-out preventers of the first group are confined entirely to the use of flush-joint drill pipe. They are not capable of operating where there is any great irregularity or variation in the diameter or circular form of the drill pipe, and since a good deal of friction must arise between the rotating drill pipe and the stationary packing, considerable wear takes place when drilling against high pressures. In actual operation one of the glands is in use at a time, and as this wears out other glands are brought into use. This type of blow-out preventer will obviously not have a very general use.

The second group brings in the automatic principle, since these are operated by the well-pressure itself. Originally these blow-out preventers could be used only with a pipe of uniform diameter, but recent improvements now allow any type of pipe to be run, pulled, or rotated without the risk of the well getting out of hand.

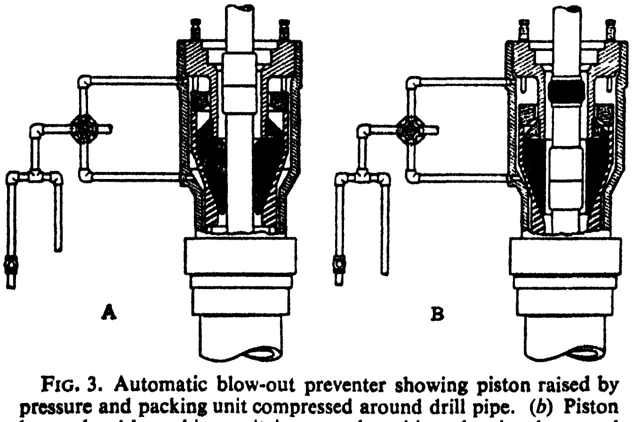


FIG. 3. Automatic blow-out preventer showing piston raised by pressure and packing unit compressed around drill pipe. (*b*) Piston lowered, with packing unit in normal position showing how tool joints, casing protectors, casing couplings, &c., pass freely through the bore.

One such blow-out preventer, which may also be included in group (*c*) as it may be operated either by well-pressure or by pressure from pumps or other suitable outside source, is shown in Fig. 3. This preventer contains a vertically movable contractor into which fits a tapered reinforced rubber packer of a special resilient composition. Under normal drilling conditions the maximum bore of the packer is large enough to allow the free passage of the drilling bit. Well-pressure compresses the packer securely round the pipe within the bore by the upward movement of the contractor, the seal becoming tighter as the pressure increases. The tightness of the seal can be controlled by adjusting screws which limit the upward movement of the contractor.

As a tool joint is pulled upward against the packing rubber the contractor moves downward automatically, carrying the packing rubber with it and allowing the rubber to accommodate itself to the tool joint diameter.

Any tendency to flow on the part of the well instantly raises the contractor and compresses the packer around the kelly, drill stem, tool joint, or drill collar, and whilst in this position the string may be rotated as well as pulled or lowered.

In cases requiring long periods of rotation with a square kelly, the life of the packer may be increased by the use of an adaptor which permits the use of a cylindrical sleeve which rotates with the packing unit.

Blow-out preventers of type (*c*) are somewhat similar to those of type (*b*) in that they are operated by pressure. In this group hydraulic pressure developed by a small weight-loaded accumulator or by pressure from slush pumps, steam supply, or a small hand pump can be used.

The rubber sleeve which packs off the annular space is mounted on ball-bearing races and rotates positively with the kelly. No wear, therefore, take place on the sleeve due to rotation of the drill stem. A certain amount of lateral movement and flexibility is possible thus relieving the well-head fittings of the strains which may be set up as a result of the table being out of alinement or the kelly bent.

A static or non-rotating type is also available embodying the same principles of operation but not providing for lateral movement or rotation. This type may be used successfully for running casing or tubing and also enables casing to be cemented under pressure.

These hydraulically operated blow-out preventers are brought into operation instantaneously by the opening of a cock placed in some convenient position.

The final group (*d*) consists of ram operated blow-out preventers of the same type as mentioned when dealing with the blow-out preventers used in normal pressure areas (Fig. 4).

The main principle of the blow-out preventer is the same as previously described, two rams being arranged on opposite sides of the body that can be forced against the drill pipe when a blow-out is threatened. For drilling under pressure a further seal is necessary around the pipe and for this an auxiliary device is installed above the main preventer. During drilling, therefore, all the wear occasioned by the rotating drill pipe under pressure is taken by the auxiliary device. When it becomes necessary to replace the seal, the rams of the preventer are closed to hold the well-pressure whilst the replacement is being made.

Snubbing gear is also essential to pressure drilling and various types are available. This gear is necessary to force the string into the well against the well-pressure until the weight of the drilling string is sufficient to overcome the pressure.

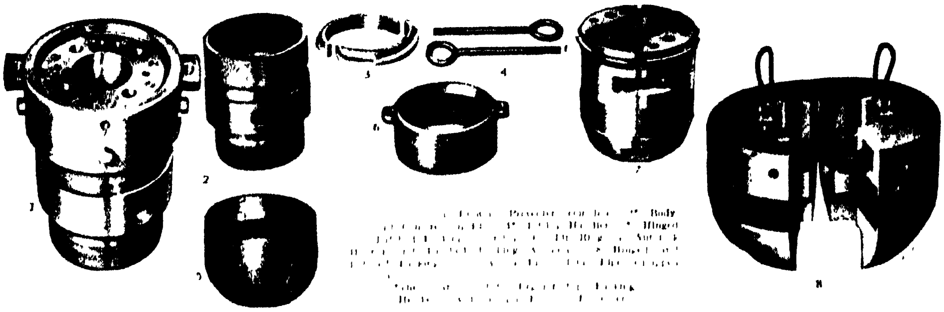


FIG. 1

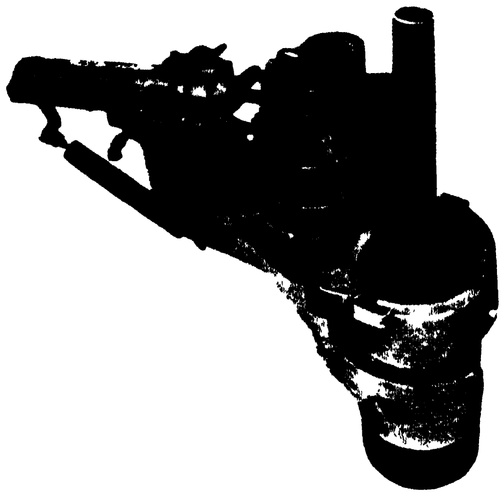


FIG. 2

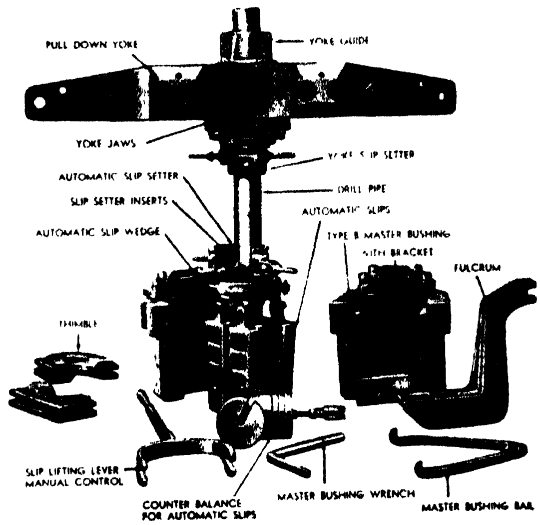


FIG. 5

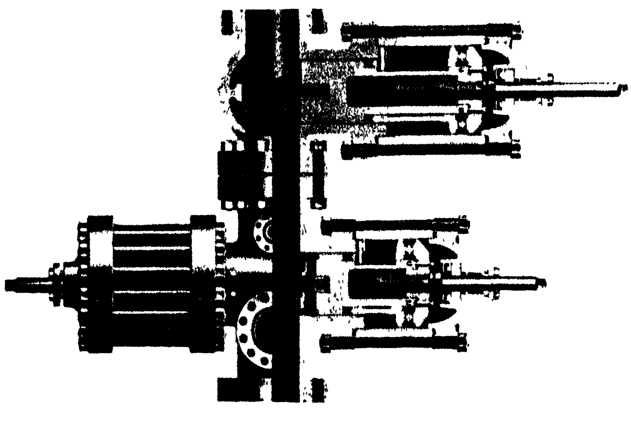
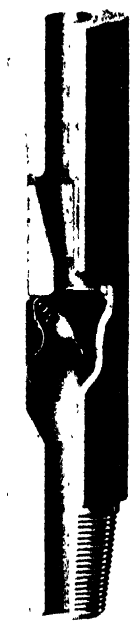


FIG. 4



Drill Pipe Float and Back Pressure Valve for A.P.I. Drill Pipe.

FIG. 6

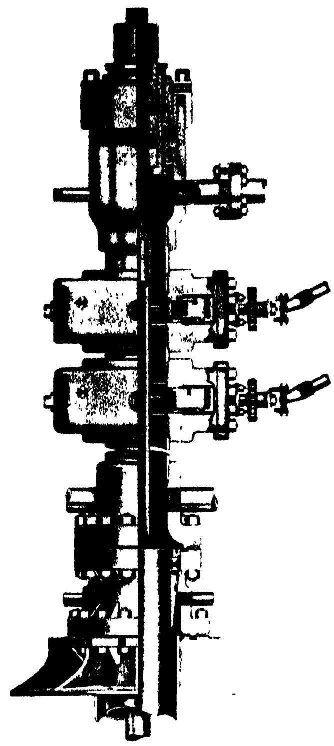


FIG. 8

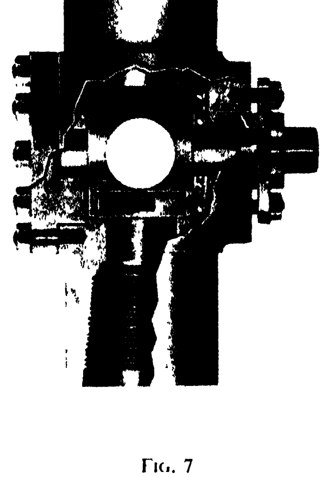


FIG. 7

The simple form of snubbing gear consists of a wire line running through a series of snatch blocks, the free end of the line being attached to a winding drum. A pull on the drum results in a downward pull being exerted on the pipe. It can only be used with light loads and where the work does not justify the expense of the more powerful gears.

A more complicated type of snubbing gear consists of a cylinder and piston fitted with dogs and operated by gas or liquid under pressure. The cylinder is fitted near the well mouth and movement of the piston results in a movement of the pipe. Thus forcing the piston downwards forces the drill pipe into the well and allowing the piston to travel upwards allows the pressure to expel the pipe under the control of the snubbing gear. The travel of the piston regulates the travel of the drill pipe and this in general is about 6 ft. The drill pipe must be raised high enough in the derrick to permit of its being lowered through the hollow ram before the usual screwing up takes place.

Another type of snubbing gear which makes use of a cylinder and ram is hydraulically operated and the actual pull is given by means of two heavy chains attached to an automatic clamp on the drill pipe. In this gear a cylinder, 12 ft. in length, is anchored at ground level and the pressure is supplied by the slush pumps. As the ram moves outwards under the hydraulic pressure the clamp is given a downward pull, which is in turn transmitted to the drill pipe. In this method the derrick floor is left clear, the only equipment above the floor being two travelling chains and the snubbing gear.

A more recent type of snubbing gear employs two hydraulic cylinders which are placed in the well cellar, one on either side of the well. Movement of the pipe is obtained by connecting the two cylinders to a yoke which carries a suitable gripping device for gripping the drill pipe as required.

Where the hydraulic rotary outfit is in use no snubbing gear will be necessary since the method of feed for this particular type of rig enables snubbing to be carried out without the addition of further equipment.

The controlled pressure drilling equipment includes a pull down yoke, automatic slips, and slip-lifting mechanism, and with the yoke attached to the drill pipe a downward pull can be applied by admitting pressure to the hydraulic cylinders for operating the pull down equipment (Fig. 5).

A set of stationary clamps must be provided to support the drill pipe whilst a fresh hold is being taken by the travelling clamps, no matter which type of snubbing gear is used.

Back-pressure valves are placed in the drilling string to prevent back flow of the well fluid through the string. At least one of these valves should be used, preferably just above the drilling bit, to enable the drilling string to be run into the well under pressure. Additional safety will be obtained by placing a second back-pressure valve at the upper end of the drill collar (Fig. 6).

The kelly cock is a high pressure, quick acting, shut-off valve placed above the kelly to protect the rotary hose and to ensure control should the well blow in through the drill pipe, or in case of failure of any part of the gear on the pump side of the cock (Fig. 7).

The wellhead fittings and their arrangement are an important consideration in high pressure drilling.

These will depend largely upon the pressures existing in the formations to be penetrated, and upon the work that has to be carried out in the well. That is to say whether it is decided to core or whether provision must be made for possible fishing jobs. The latter operation is a probability, and it would, therefore, be expedient for the wellhead fittings to be so arranged in all cases.

Safety and flexibility should be the aim of all wellhead arrangements and this may necessitate the duplication of the various fittings to provide against possible failure at a critical moment.

The arrangements at the wellhead will in general follow more or less stereotyped lines—in that landing heads for each string of casing run, high-pressure mud cross with outlets for mud line connexions, cellar control gates, one a master gate for protection when the pipe is out of the hole and one for protection when the pipe is in the hole, and a blow-out preventer of some type, preferably rotating, to ensure protection under any contingency that may arise when making hole, must be provided. Any additional equipment or duplication of any of these standard parts will depend entirely upon the particular conditions encountered. A wellhead arrangement made up as stated will definitely provide complete safety during drilling, even in wells of abnormal pressure.

Where a hydrostatic pressure can be used to control formation pressures this wellhead arrangement will be found quite satisfactory, and should gas cutting or the unexpected penetration of a high-pressure zone occur whilst the drill pipe is being rotated all danger of a blow-out will be eliminated by the rotating blow-out preventer. At the same time the necessary means can be taken to condition the mud to handle the pressures without danger to the fittings or the crew.

An ideal drilling hook-up is shown in Fig. 8. With this arrangement 'pressure drilling' can be carried out and the drill pipe easily and safely run-in or pulled out under pressure. During drilling the kelly is packed off by the rotating square packing assembly which acts as a stuffing box for the kelly. In order to remove the drill pipe the kelly is raised until the joint connecting it to the drill pipe is located between the upper control gate and the blow-out preventer. The control gate is then closed around the drill pipe to confine the pressure, and the rotating packing assembly is then ready to be removed together with the bonnet which has been unscrewed from the main body.

The kelly is then raised, together with the packing assembly and bonnet, until it can be removed from the drill pipe.

The drill pipe is pulled up sufficiently to allow a non-rotating packing assembly, which fits snugly around the pipe, to be placed in the body of the preventer. This assembly is held in place by a steel slotted bonnet and acts as a stuffing-box as the drill pipe is pulled, the gate rams having been opened. As the tool joints reach the packing assembly the upper gate is closed and the packing assembly is removed as the tool joints or collars lift it from the body of the preventer. When the tool joints have cleared the top of the preventer the packing assembly is replaced and the operation is repeated throughout the string.

It will be seen that complete control is maintained throughout the operation of running in and pulling out the drill pipe.

Where a rotating blow-out preventer of the type mentioned in group 2 is used there is no necessity for the use of a non-rotating packing assembly or for the closing of the control gate whilst the pipe is being unscrewed. With this type of blow-out preventer the packers close around the pipe all the time the pipe is in the hole.

Coring and fishing can be carried out in the normal way without any interference with the wellhead fittings.

When the bit, core drill, or fishing tool has passed through the main control gate, this will be closed to completely close the well against any pressure from the bottom.

The provision of beans in the mud discharge lines from the well will enable control of the flush return to be maintained in relation to the pump input. Where the pressures are high control may be maintained by an enclosed system of flush return. In this case the load on the slush pumps is reduced. The usual method is to instal a series of pressure tight pipes through which the flush return is passed, and after settling the mud is picked up by the slush pumps at practically the same pressure as that at which it left the well.

Drilling in high-pressure areas involves certain risks, but the adoption of equipment such as has been referred to will reduce the risks to a minimum. The use of high-pressure equipment and weighted mud together, where conditions are suitable, will still further increase the ease with which high-pressure areas can be drilled and controlled.

Objections can be stated to the use of weighted muds especially when drilling through oil-sands and limestones. One of the principal functions of drilling mud is to seal off the formations passed through and the possibility of an oil-bearing sand being mudded off cannot be ignored. A reduction in the productivity of the well may quite easily result from the use of mud without the operator being completely aware of it. Further, the difficulty of obtaining supplies of suitable weighting materials may add considerably to the cost of drilling and may make the operation an uneconomic one.

High pressures can be controlled by the application of a pressure, at least equal to the well pressure, and this can be provided by

(*a*) the static pressure exerted by a column of fluid.
(*b*) the static pressure exerted by a column of fluid together with an additional pressure exerted at the top of the column of fluid.

The first means of applying pressure has already been mentioned and it is by the latter that the greatest latitude is provided. By this means the specific gravity of the column of fluid can be reduced without affecting the effective pressure exerted at the bottom of the well. Under these conditions the pressure exerted by the column at any point in the well will correspond closely to the pressure encountered in the formation. The differential pressure is reduced to a minimum by this method and difficulties such as lost circulation or dilution of the drilling mud can be overcome to a large extent.

Pumps will, in general, supply the external pressure necessary in pressure drilling, and it can be stated that, in all cases, pressure drilling involves a control of back pressure held on the circulating fluid. The fluid in pressure drilling may be light or heavy depending upon the conditions imposed, but in all cases it will have to be conditioned properly.

Pressure drilling will be found advantageous in a number of cases other than where high pressures are encountered, and these include (1) when gas cutting will endanger the operations, (2) when formations must be mudded off without the use of weighting materials, (3) when heaving shale is caused by formation pressure and may be confined by maintaining a formation pressure in excess of that in the formation, &c.

Drilling will be carried out in the normal way with possible slight differences in the technique of landing and cementing certain strings of casing [1, 1933].

The necessity for holding high pressures on the formation resulted, in many cases, in contamination of porous oil zones with consequent inaccuracies in the well logs. Cores removed from wells completed under pressure were often impregnated with drilling fluid and were in such a condition that an accurate geological investigation was impossible. This condition applies equally to deep wells in areas of moderately low pressures. The resultant hydrostatic pressure imposed on the formation permitted the fluid to penetrate the productive sand and to interfere with the natural capacity of the well to produce. In many cases the wells would not flow naturally on completion.

As a result of the difficulties encountered in penetrating deep high-pressure formations experiments were carried out with a view to utilizing the formation pressure in reversed circulation to carry the cuttings to the surface up the drill pipe instead of up the conventional path.

The employment of this method requires that the oil produced during drilling must be handled, stored, or disposed of as produced.

The pressure-drilling equipment as previously described is employed, except that no slush pumps are required. The flow of the well will be utilized to carry the cuttings to the surface, and this is a distinct advantage where losses of mud fluid would be normally experienced.

A back-pressure valve was designed and placed immediately above the bit and so arranged that when the bit struck bottom it would open and allow the formation pressure to force the fluid and cuttings up the drill pipe.

This special valve allows the drill pipe to be run in and out of the well since it operates only when the bit is actually drilling.

Cuttings removed from the well would be in a much more satisfactory condition for geological examination, and should the drill pipe tend to stick at any time the flow of the circulating fluid could be reversed to clear away the caving formations from the pipe.

This method of controlled drilling did not become completely popular, and the present-day controlled pressure-drilling method was instigated.

The principal difference between this method and the normal rotary drilling practice is in the use of oil or a mixture of oil and gas as the circulating fluid in place of mud. The flow from the well is controlled during drilling by the use of special control equipment. The flow of the circulating fluid follows the same path as the normal drilling fluid used in rotary drilling, that is up the annular space between the drill pipe and the walls of the well, and by means of a packing arrangement at the surface between the pipe and the casing the flow from the well is confined to a closed system of surface lines and tanks. The usual hazards that accompany the conventional completion practices are thus eliminated.

Flow from the formation is permitted throughout the drilling-in process and progressive testing of the formation is thus possible, allowing a continuous record of the capacity of the well to produce to be obtained. The cuttings made are removed from the well at a higher velocity with this method than is the case with mud flush and logging of the formations may be carried out with greater accuracy. In addition the samples are uncontaminated by mud or other foreign matter and better geological examination is possible. Furthermore, during drilling-in the exact position and character of water sources can be determined and expen-

sive plugging-back operations may be avoided by the early discovery of bottom water.

The hole is kept clean of cuttings and a noticeable reduction of bit wear and an increase in drilling speed have been experienced.

Due to the fact that the wells are flowed at their full capacity when completed by the controlled pressure method, less cleaning out is necessary after they are put on production.

For the successful operation of this method some form of packing assembly must be installed between the casing and drill pipe which will allow the pipe to move both rotationally and vertically whilst maintaining complete control. This packing assembly may take any form so long as it will carry out this important function.

Either a round kelly joint and a rubber packing assembly or a special square kelly joint packer, used in conjunction with a split rubber oil saver, may be used successfully.

The hydraulic rotary rig may be used to advantage in this method of drilling since flush joint drill pipe is normally used and the pipe may be rotated and run in and out of the hole through a rubber packing head.

Where the hydraulic table is not used a special round kelly driving device may be installed for driving the flush joint drill pipe with the conventional rotary table. An advantage of this arrangement is that the flush-joint drill pipe may be run-in and -out of a rubber type packing head, or through a blow-out preventer, under high well pressures without leakage and with a minimum amount of wear on the rubbers.

For the operation of the square kelly a packing head is provided which rotates with the kelly and at the same time permits vertical movement of the string. Packing rings and pressure seal packing are provided to prevent leakage past the kelly and past the retaining bowl and core of the packing head. Delay in running in and out is occasioned by the use of the normal type kelly joint since the vertical movement of the kelly is limited to the length of the joint itself. A rubber oil saver, generally of the double ram type, is located beneath the kelly packer and the rubber rams in the oil saver must be closed before the kelly packer is removed. In addition there is rapid wear of the rubber due to the passage of the tool joints through the saver whilst manipulating the drill pipe into or out of the hole.

Where there is a danger of cutting of the wellhead fittings local regulations may specify special preparations and auxiliary equipment. The blow-out preventer may be placed below the steel cross as a precaution against cutting of this part of the equipment and the master gate may be duplicated to ensure complete control where sand is being produced in large quantities. In very high-pressure areas two blow-out preventers may be installed.

Since a closed system of surface lines and tanks is used a circulating tank of sufficient capacity, connected to the oil and gas separator and to the circulating pump, must be provided. In high-pressure fields, and in areas where only oil is used as the circulating fluid, the ordinary mud pumps may be used, but where the formation pressures are low and only a small quantity of oil is circulated small pumps may be all that is required.

In systems where a mixture of oil and gas is injected the high-pressure gas connexion is made at the bottom of the stand pipe and a steel hose of the multiple swivel joint type is generally used in preference to the rubber hose, the rubber lining of which may deteriorate on contact with the oil and gas.

All gas injected into and produced from the well is metered and the oil produced is gauged in order to give all possible information of underground conditions. Some means for collecting samples is also provided in the flow line leading to the separator to enable the operator to determine at any desired moment the type of formation through which he is passing.

The general procedure followed in controlled-pressure drilling is similar in all districts, but small details of operation may occur depending upon local conditions.

Mud fluid is used until the last water string has been set and cemented and whilst waiting for the cement to set the wellhead fittings, separators, and storage tanks are installed.

The cement plug is drilled out with water as the circulating fluid and after a new bit has been added this water is lifted out of the well in stages as the bit descends. When the bit reaches bottom circulation is established, using oil or a mixture of oil and gas. Drilling then proceeds with this as a drilling fluid, and where formation pressures are high enough the well may flow naturally during the time hole is being made. In some areas dead oil used as the drilling fluid is sufficient to maintain the well in a static state, but the injection of a small quantity of gas to the oil column causes the well to commence flowing.

Excessive back pressure on the surface fittings and the control equipment is not necessary if ample separator capacity is provided and flow lines of the proper size and storage tanks of sufficient capacity are installed. Under these conditions flowing pressures seldom exceed 100 lb. per sq. in. The rate of flow is reduced by the friction due to the casing and drill pipe in the hole so that one, and in exceptional cases two, separators can handle the production without excessive back pressure. This condition holds for flowing pressures only, as high pressures may be experienced if the well is shut in at any time during drilling.

It must not be assumed from what has been said that controlled-pressure drilling is a hazardous oilfield operation. Completions by this method are not necessary high-pressure operations. Wells may be completed under pressure control without having to combat pressures approximating to those of the well when closed in. Various factors, such as the choking effect of the drill stem and the loading effects of the pumps enable the well to flow at low surface pressures without necessarily maintaining a dangerously low bottom-hole pressure. Controlling the amount and gravity of the fluid circulated permits a control of the flowing pressure maintained on the sand during the drilling operation to a large extent.

The tubing of high-pressure wells is no more difficult than running the string of drill pipe where the tubing is run in and out of the hole through rubber type oil savers. It is the general practice to run tubing before the drilling rig and control equipment are removed instead of snubbing it in against the shut-in pressure after the well is completed.

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CORE DRILLING

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A KNOWLEDGE of the subsurface formation penetrated by the drilling bit is of paramount importance in the economic drilling of an oil-well and one of the outstanding contributions to oil-well drilling has been the development of highly efficient core drills.

Prior to the development of coring, the only means available for obtaining knowledge of the underground conditions was by an examination of the cuttings being brought to the surface by the circulating fluid where rotary was being used or by bailing in the cable-tool system. Whilst these methods conveyed some idea of the nature of the strata penetrated, many valuable characteristics and structured features were destroyed by the action of the bit and the mudding action of the fluid in the hole. The cuttings, particularly in the case of the rotary system, were contaminated with the drilling fluid and, in addition, no definite estimate of the time taken by the cuttings to travel from the bit to the surface was possible. The possibility of cuttings falling back in the flow of fluid for even a short period could not be taken into account, and it is obvious that should such a condition occur the cuttings would not be received at the surface in the order in which the formations were penetrated.

This uncertainty in the identification of the drilling returns led to the development of coring devices to enable uncontaminated samples or unbroken cores of the formations to be secured. From these cores it was possible to correlate geological data and so build up well logs of much greater accuracy than were possible from the reports of the drillers and an examination of the cuttings.

Most core drills are slow in their action and somewhat unreliable in that it is doubtful whether more than a very few cores are 100% complete. The advent of the so-called electrical coring, this should be referred to as electrical logging, has reduced the necessity for the mechanical coring devices to a great extent, but it is impossible to eliminate them entirely. These two methods used in conjunction with one another should enable very complete well logs to be drawn up.

Although core drilling has been in existence for more than 70 years, it was not until 1921 that it came into general use. The first core drill was the invention of a French engineer in the year 1863 when a diamond core drill was used in mining operations. This drill was designed for use in hard rock and consisted of a hollow steel ring into which black diamonds were securely set. The rock was cut by the diamonds and the steel ring followed the groove so cut. The material which passed inside the ring formed the core and was firmly held inside the core barrel. This core drill is pre-eminently satisfactory for drilling small holes in hard rock, and was the forerunner of the rotary core barrel, the same principle being used in its development.

Rotary Core Drills

Core drills may be grouped into two general groups, one which cuts and removes a solid core retaining the strata in their respective positions as passed in the well and the other removing a mass of cuttings uncontaminated by mud or well fluid. The second group is more correctly termed a 'sampling device'.

In the first group there are, the single barrel, punch, auger, fishtail, shot drill, double barrel, and wire-line core barrel. Many of these are no longer used but the principle of each may be seen in the modern core drill.

Three separate and distinct types of core barrels are in use to-day: (1) The rotary core barrel for soft and medium hard formations (Fig. 1), (2) core drills designed for use with very hard formations (Fig. 2), and (3) core barrels for use with the standard cable tool system (Fig. 3).

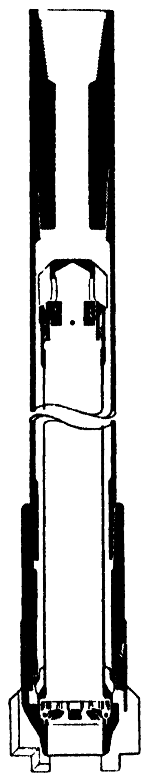


FIG. 1.

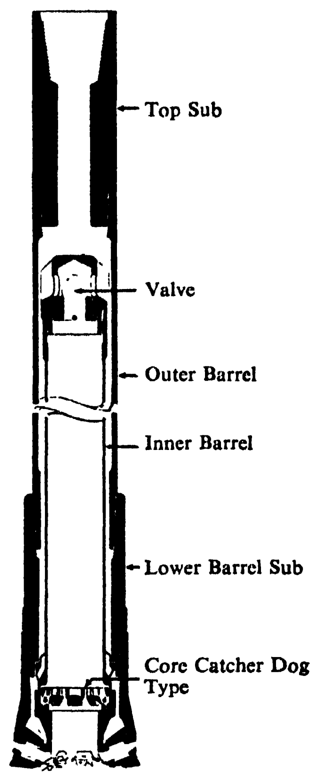


FIG. 2.

Although slight variations have been introduced in many of these core drills the general parts are the same and they operate on the same principle.

The main parts of a core drill for use in soft to medium hard formations are:

a. Cutter head.
b. Core catcher.
c. Cutter body.
d. Lower sub.
e. Inner barrel.
f. Outer barrel.
g. Upper sub.

Various types of cutter heads are available for soft and

medium hard formations, but in general they are of the multi-toothed types. The object of the cutter head is to make hole and to cut and shape the core. Thus the cutter head will consist of cutting teeth, reaming teeth, and an inner series of teeth to shape the core after the cutting teeth have done their work. This inner series will also prevent, by virtue of the design of the teeth, any particles of cuttings from entering the core barrel with the solid core.

The cutter teeth of the cutter head vary in number from two to four, and on most heads are placed so as to drill the hole to gauge. Where the head is equipped with reaming teeth the cutting teeth may cut an undergauge or pilot hole, the reamers drilling the hole to gauge.

Reaming teeth which vary in number from two to four are constructed so that they keep the hole true to gauge at all times. Any irregularity passed by the cutting teeth should be cleared by the reaming teeth.

The general practice is to face the cutting and reaming teeth with special hard facing alloys to increase the working life of the teeth.

Various types of core catchers are available, the most popular type being the ring or spring type (Fig. 4). These catchers may be used with either hard or soft formations. In caving formations a 'mousetrap' core catcher may be satisfactory.

The ring-type core catcher consists of a ring of metal, usually of a different metal from that of the core barrel, with an inside diameter slightly larger than the diameter of the core to be recovered. Around the periphery of this ring a number of steel springs or pawls are placed projecting upward and slightly inward, so that the core on entering the barrel will spread them apart but maintain sufficient pressure to free the upper edges of the springs into the core when the core drill is raised. By this means the core is prevented from falling out during the upward journey to the surface of the drill. The ring rests on a shoulder on the cutter head and is held in place by the cutter body.

Another type is the spring actuated dog type of core catcher which has spring operated dogs in place of springs (Fig. 5). A third type is a combination of this second type

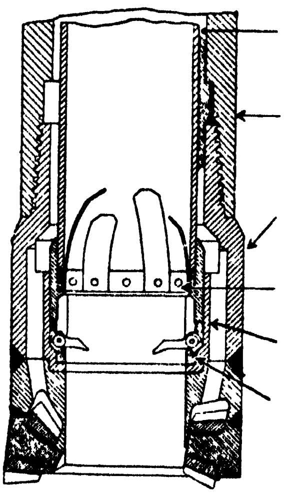


FIG. 5.

and a series of slips adapted to wedge in a tapered bowl around the core when the bit is lifted (Fig. 6). The slips tighten when the core is broken off at the slips or below them. Whilst a fourth type is a core catcher of the dog type as shown in Figs. 1 and 2.

The cutter body or drill barrel assembly consists of a cutter body, a lower sub, an outer barrel and an upper sub. The cutter body, to which is screwed the cutter head, is of heavy seamless steel tubes, or in some cases seamless upset drill pipe. The upper end of this body is screwed to take the lower sub and in some drills the inner barrel. The cutter body is so constructed that the circulating fluid may pass down the circular space between the body and the inner barrel, through holes drilled in the cutter body, and thence to the cutting elements, where it performs the same functions as in standard rotary drilling.

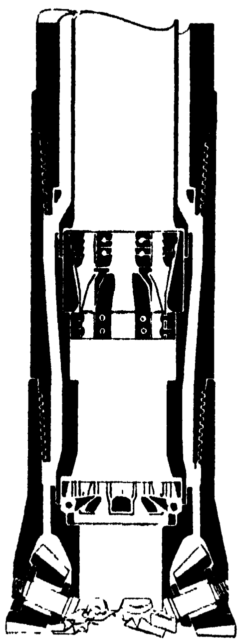


FIG. 6

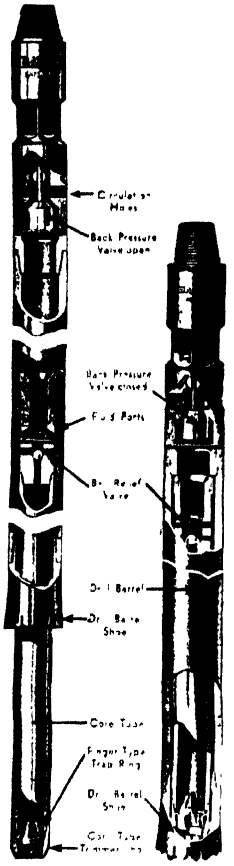
The lower sub is the connexion between the cutter body and the outer barrel and is added to the string to strengthen the lower end of the cutting assembly and to facilitate the breaking down of the barrel. The lower sub is considered unnecessary by some companies, and in these cases the outer barrel screws directly into the cutter body.

The function of the inner barrel is to receive and protect the core as it makes its way through the bit. The length of the barrel will vary with the particular well but will be from 10 ft. to 20 ft. long under normal conditions. It screws into the cutter body or the cutter head at the lower end. At the upper end of the barrel an ordinary ball-and-sub valve is located. This valve enables fluid inside the barrel to escape into the circular space between the outer and inner barrels but prevents the circulating fluid from entering the inner barrel. This fluid is forced down the annular space to the bit. Several modifications to the construction of the inner barrel are available. Instead of the inner barrel being screwed to the cutter body or cutter head it may float on ball bearings. The barrel does not rotate with the cutter head and cutter body but remains stationary with the core. The advantages of such an arrangement are that there is less possibility of the core being twisted off as it rises in a moving core barrel and burning of the outside of the core from friction between the core and the core barrel is eliminated.

A number of core barrels are being sectionized so that the core may be removed in short sections, whilst in some cases a liner is placed inside the core barrel to receive the core. This liner is split in two longitudinal sections so that on removal the full length of the core is available by removing the two halves of the liner and gives an added protection to the core on removal from the barrel.

The outer barrel is the connexion between the cutter head or lower sub and the upper sub and forms a protection for the core barrel. It also serves to form an annular space between the inner and outer barrels down which the circulating fluid may pass to the cutters.

The upper sub connects the outer barrel, and hence the remainder of the core drill to the drill string, and is made of a similar material to the drill pipe. A special type of overshot elevator sub is available for all general coring operations. It is designed to take both elevators and slips



Cable Tool Core Barrel—Left at upstroke; right at down stroke

FIG. 3

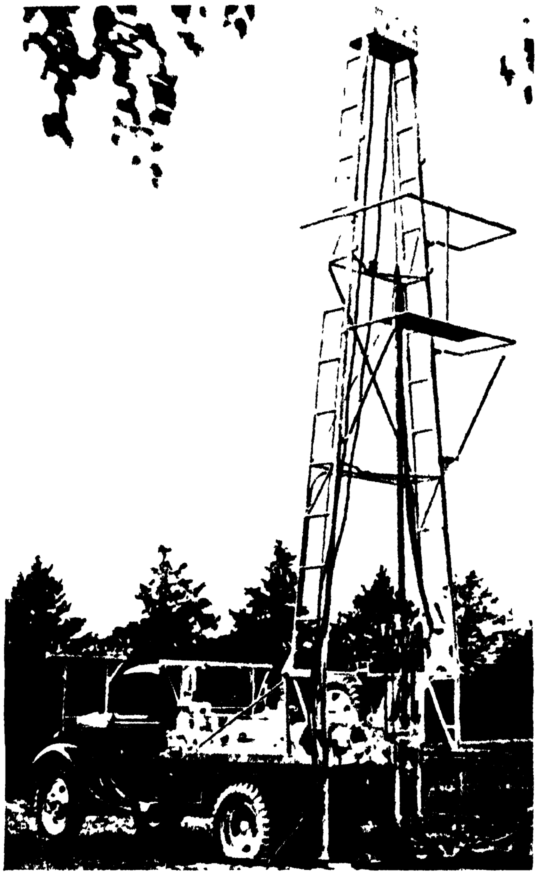


FIG 10

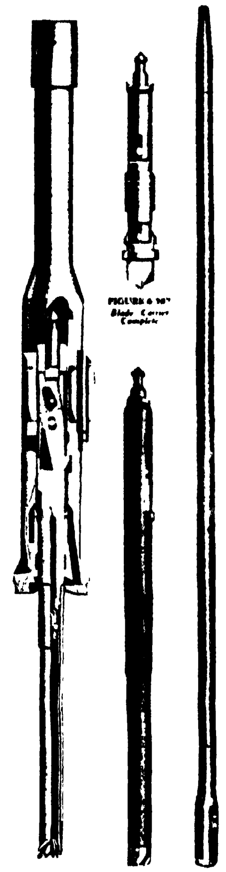


FIG. 8

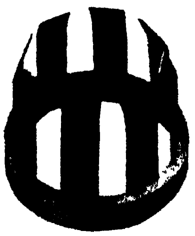


FIG. 4

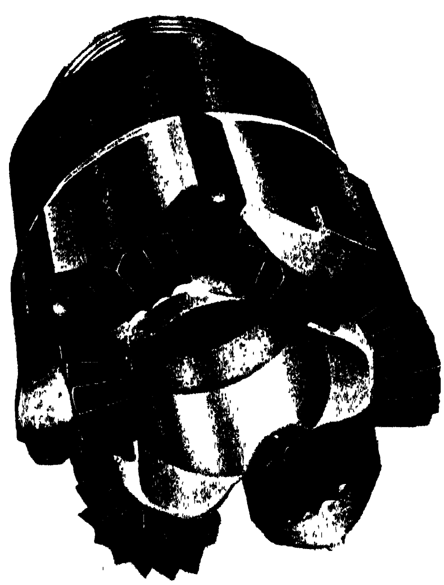


FIG. 7

simultaneously and eliminates the use of ropes for handling the core barrel, thus providing a much higher factor of safety.

Hard rock rotary core bits are available, the design of the bits being similar to the rock bits used in ordinary rotary drilling but with space available at the centre for the equipment of the core barrel (Fig. 7). These bits may be toothed rollers and the cutting action is comparable to attacking the formation with hammer and chisel. As the bit rotates the hammer effect is present, while the teeth of the roller chip away the formation in the same manner as the chisel.

Reaming of the hole during coring may be accomplished by equipping the bit with a special reamer body, carrying a number of reamers, which is screwed into the string immediately above the cutter head or by building up the outer jaws of the inner set of cutters to gauge with hard facing alloys so that they form projecting lugs.

An interesting modification of rotary core drills is the retractable core drill. These core drills have been developed for the purpose of permitting coring without the necessity of removing the drill pipe and bit from the hole when the core barrel is full of core and are ideally suited to exploration work.

There are several designs of these core bits and they may be divided into three general classes. The first two classes are provided with a wire line for retrieving the core barrel. One has the core barrel seat in the cutter head and the main cutter head forms the core. A sub locks the inner tube in place and free movement of the inner tube with the core is permitted (Fig. 8).

The other type has a core head on the inner barrel that provides a new shoe each time for forming the core. The barrel is locked against rotation and protrudes a short distance ahead of the drilling bit. Should a very hard formation be encountered the shoe is permitted to move into the head against the pressure of a spring.

The third type has a similar head to the first group but is held on to its sub by pump pressure. Any obstruction to the passage of the core into the core barrel results in the inner barrel rising and an increase in pump pressure. The inner barrel can then be pumped out of the string by reversing the direction of the circulating fluid or by means of a fishing-tool run on a wire line.

In the first two groups a core barrel of from 2 to 4 in. in diameter, equipped with a head of special design is dropped into the drill pipe. This barrel is about nine feet long and at the conclusion of this depth the drilling string is raised to allow the kelly to be disconnected and the string is supported by the table slips. A small overshot tool is run into the drill pipe on a wire line. The overshot takes a grip on the special head of the core barrel and permits the removal of the barrel. All the retractable-type core barrels are suitable for work in relatively soft formations or in those which would be drilled with a drag type bit.

Standard Cable-Tool Core Drills

Coring by the standard cable-tool system is slightly more complicated than by the rotary system. In the cable-tool system drilling is accomplished by a vertical reciprocating motion as opposed to a rotary motion in the rotary system. Thus the drilling bit in the cable tool system is continually leaving the formation and without the specialized method of coring which has been devised complete and accurate information as to the character of the formation being penetrated could not be secured with this system of drilling.

The modern cable-tool core barrel (Fig. 3) consists of two principal parts, an outer drilling barrel and an inner core-retaining tube.

In action the inner barrel rests on the formation all the time drilling is proceeding, whilst the drilling barrel is given the usual vertical reciprocating motion as when drilling normally with the cable-tool system. The outer or drilling barrel slides over the inner barrel and cuts away the formation around it enabling the core-retaining tube to follow down over the core.

The inner barrel consists of three main parts, the core-tube head, the core tube, and the core-tube trimmer-shoe with core retainer.

The core-tube head is constructed with a shoulder at the upper end which may contact with a similar shoulder cut into the drill-barrel head, and is screwed into the top of the core tube. In the core-tube head a ball-check valve is used to permit the escape of drilling fluid which may be trapped in the core tube as the core rises. The outlet of the core-tube head is bevelled and provided with a fishing 'throat' to permit the use of a spear for recovering the core-retaining tube should it become necessary.

The core tube is a length of seamless steel tubing threaded at both ends for connecting the core-tube head at the top and the core-tube trimmer-shoe at the lower end.

The core-tube trimmer-shoe is screwed on to the core tube and is equipped with a sharp bevel edge, faced with a special hard-facing alloy. This shoe is generally slightly smaller in diameter at the bottom than it is at the top, so that the core cut is smaller than the inside diameter of the inner barrel. In some core barrels the smaller diameter of the inside cutter is the only means provided for retaining the core. This method depends upon the presence of sand particles to form a wedge between the core and the barrel.

In the majority of cases core-retaining rings similar to those used with the rotary system are provided. These retaining rings are held in place between the core-trimmer shoe and the core tube by shoulders on each of the separate parts.

The outer or drilling barrel is also composed of three essential parts, the drill-barrel head, the drill barrel, and the drill-barrel shoe.

The drill-barrel head screws into the box of the drill stem and a pin at the lower end screws into the top of the drill barrel. A back-pressure valve that opens downward is provided, with circulation holes in the head immediately above the valve to permit drilling fluid to enter the chamber which contains the valve. The fluid is thus permitted to pass the valve in a downward direction and is deflected into the annular space by the closing of the valve at the top of the core-tube head.

The drill barrel is usually made of heavy seamless steel tubing threaded top and bottom for connexion with the drill-barrel head and the drill-barrel shoe. It serves as a housing for the inner barrel assembly.

The drill-barrel shoe is a multi-toothed bit, the teeth of the bit being staggered to prevent key seating and usually faced with a hard-facing alloy. A clearance is provided at the cutting-edge which allows the barrel to drop freely in the hole. The bit is connected to the lower end of the drill barrel with a special tool joint, and since the inside diameter of the shoe is smaller than the inside diameter of the drill barrel, a shoulder is formed. On the top of the core-retaining tube another shoulder is provided, and where this shoulder comes into contact with that left above the drill-barrel shoe the core-retaining tube is prevented from falling

out. Watercourses are arranged on the inner surface of the bit to allow free passage of fluid from within the drill barrel to the cutting-edge of the shoe.

The operation of the core drill depends upon the exact determination of the action of the tools. At no time during drilling must the core-trimmer shoe leave the formation, and in order that this may not occur the stroke of the drilling bit must be shorter than the length of the core-retaining tube, for if the shoulder above the drilling bit should come into contact with the shoulder at the top of the core-retaining tube before the completion of the upstroke, the core-trimmer shoe will be raised from the formation and there is the possibility that the core may escape.

On the upstroke of the drill barrel a certain quantity of fluid is drawn through the circulation holes into the chamber holding the back-pressure valve, and this fluid fills the chamber formed by the top of the inner barrel and the top of the outer barrel. On the down-stroke the two back-pressure valves close and the fluid trapped in the chamber is compressed, causing a blow to be imparted to the inner tube and at the same time forcing the fluid down the annular space between the outer and inner barrels to the bit.

Cores can be removed from the drill by unscrewing the drill-barrel shoe and removing the core-retaining tube.

Little difficulty need be experienced in taking a core with modern core drills of whatever type, but slightly more care must be exercised during drilling.

All watercourses must be perfectly clean, and the core catcher must be free to rotate in its recess, the ball-and-seat valve must be clean and in good condition, and all joints in the assembly must be tight.

Before commencing to drill it is advisable to equalize the mud column and wash away any cuttings that may have settled in the bottom of the hole. If possible the mud should be changed, and in certain circumstances a change to oil as the drilling fluid may be recommended.

The speed of rotation of the table should be considerably less than normally used during ordinary drilling and the weight on the bit should be a medium weight. It is found that such a weight gives better results than could be obtained with a 'spinning' action. When sufficient core has been taken the speed is increased before the tools are lifted to break the core at the bottom.

With the cable-tool system the rate of strike should be considerably slower than a drilling strike.

Wall Sampler

A rotary wall sampler is available, and this tool enables samples of the walls of an open hole to be taken at any desired point (Fig. 9). This tool will be found ideally suitable for restoring lost core records or for checking formations which were not cored when drilled through.

The tool consists essentially of a wall scraper to which a set of sample blades have been added. Each sample blade has two core-taking tubes screwed into the upper section.

Whilst the tool is being run into the hole the blades remain safely inside the body of the tool, but when the desired point is reached pump pressure applied at the surface pushes down the enclosed piston which expands the blades outwards and upwards against the formation. With the pumps still running the weight of the string of drill pipe is slowly placed upon the tool, forcing the blades into the formation and the cores into the blades.

When pump pressure is removed the blades close safely into the body of the tool.

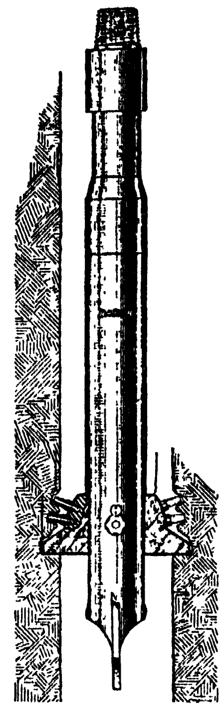


FIG. 9

Prospecting Rigs

The core drills first used for prospecting were of the steam-driven type which had been used successfully for many years in coal and metal prospecting. Water difficulties made the use of these rigs unsatisfactory, and experimental work was carried out on the use of other prime movers for the purpose.

The transportation of these steam-driven rigs became a serious item and portability received serious attention.

The result is that portable rigs are available to-day which are capable of drilling to 6,000 ft. with 3-in. drill pipe which can be driven up to the location and drilling may commence within a few hours of arrival.

Various types of small rigs are available operating in different ways from those utilizing the full power of the truck motor to those having separate power units for the draw-works, table, and slush pump. In general these prospecting units are truck mounted and all the necessary equipment such as water tanks, fuel tanks, &c., may be mounted on trailers or on specially designed skids (Fig. 10).

The hoisting mast of these units consists of a 28-ft. A mast of welded tubular steel which is pivoted between the rotary table and the draw-works. The legs of the masts in the larger sizes rest on the ground when in position, but on the smaller rigs they rest on the truck frame. When location has to be changed the mast is lowered on to permanent rests placed on the truck. Raising and lowering of the mast is accomplished by means of the hoisting-line operating through pulleys fastened to the truck frame and to the base of the mast. Masts of greater length than normal will be hinged and the upper part folded back.

The equipment used with these prospecting rigs is precisely the same as that used with the standard rigs, except that it is lighter and the space allotted to each part, smaller. Certain parts may differ slightly in appearance, but the

work they accomplish will be the same as that accomplished by the full-size parts.

Even the hydraulic table is to be found among these rigs. The travel of these tables does not exceed 30 in., and where thrusting ranges exceed 18 in. it has been found advisable to use twin cylinders with a connecting yoke through which the drill pipe is inserted. The table is operated by a closed oil-pressure system on account of the wear experienced when mud is used to force the table up and down. A small hydraulic cylinder and piston is used to move the drilling machinery to and from the hole.

The core bits used may be the annular tapered inside bits similar to those used with black diamonds. In place of the diamonds hard-facing alloys are now welded on to the cutting-face of the bit, and clearance has been measured both on the outside and inside of the ring.

The standard double-tube core barrel similar in design to that already described is generally used, the size of the barrel depending upon the size of the hole being drilled.

The speed of rotation of the prospecting rig will not exceed 200 r.p.m., and any speed between 50 r.p.m. and this figure may be selected at the discretion of the driller. Coring is generally done at a slower rotating speed and with much less downward pressure on the bit than is the case with ordinary drilling.

Seismograph shot-holes are an important duty of the prospecting rig, and whilst this method has proved faster and cheaper as a means of exploring for petroleum, there are certain areas where mechanical coring can give an accurate and economical mapping. In both these duties the prospecting rig is ideally suitable, and its future work will, in the main, be confined to them.

DIRECTED DRILLING

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THE drilling of holes by the rotary system demands the consideration of a number of factors, among which may be quoted the necessity for controlling the action and direction of the bit at all times. This applies equally whether a vertical hole is desired or whether the hole is to be deliberately drifted. Where a vertical hole is intended any deviation from the vertical course will increase the cost of drilling, lead to incorrect geological interpretation of formations, and when artificial means for producing become necessary the lifting cost is increased. A careful analysis of drilling would indicate that whatever precautions are taken to control the bit throughout the whole course of the well, extraneous conditions will arise which will mitigate against complete success. Four critical factors must be examined to determine the possibility of drilling a controlled hole. These are: critical angle of the formations, critical weight exerted on the bit, critical speed of rotation of the drilling string, and critical depth. The critical angle of the formations and the critical depth of the hole are factors outside the control of the driller, but critical weight and critical speed can be controlled within certain limits. These limits are obviously those which will permit hole to be made. Insufficient weight on the bit and insufficient speed of rotation will result in small or no footage, whilst too much weight on the bit and too great a speed of rotation will undoubtedly result in deviation and, probably, rupture of the drilling string.

Any or all of these factors present will increase the difficulty of completing the hole at the desired point.

It must be remembered that these factors apply to directed drilling in exactly the same manner as in straight hole drilling, since in both cases the bit must be steered along a definite course. The problems in directed drilling are, however, accentuated, since here the bit is to be steered along the arc of a circle, and if complete success is to be attained no deviation from this path must be permitted.

It has been generally stated that provided (1) only a reasonable weight is permitted on the bit, (2) the bit is true to gauge, (3) the proper pump pressure is applied, and (4) the drill pipe is kept in tension for as great a depth as possible, a straight and vertical hole is possible. It will readily be seen from an examination of the four critical factors previously mentioned that without some kind of control, straight holes are no more probable than if the generally stated measures are not considered. When considering these measures in the light of directed drilling, all but the one concerning the gauge of the bit can be ignored, since pump pressure has the effect of adding tension to the string, in other words, of lowering the point of tension and compression without reducing the weight that can be applied at the bit, and the maintenance of the string in tension would prevent the column from turning through the necessary arc, unless some means were used to force the string out of the vertical.

All drilling by the rotary system may be termed controlled or directed drilling, but the term has only been applied generally to the deliberate drifting of holes. The practice has, however, been used not only to establish and maintain a specific drift but also to straighten holes which have deviated, to sidetrack lost tools, and to obtain geological information by drilling several shallow holes from the same location.

Directed drilling means, therefore, the controlled steering of a drill stem in the desired direction to a given location below the surface and does not differentiate between the drilling of a straight hole and a deliberately drifted one.

The occasions on which a deliberate drift of the hole is an advantage are many, and a satisfactory completion in the desired position may show a considerable saving in drilling costs. The offshore locations in the Gulf Coast area and in many other places require the erection of piers as foundations for the drilling rigs, and erection costs must of necessity be greater than they would be in the case of a shore location. Further reductions can be made by drilling several holes from the same foundation and derrick by properly directing the bit over an area equal to that of a number of normal locations. Where piers are already erected the drilling of a number of holes from the pier would show a considerable saving in erection costs. The difficulties and expense of drilling from an inaccessible surface location may be overcome by the selection of a more convenient and accessible location as a drilling site.

Considerable depth of hole may also be saved by the selection of a topographically lower location.

One of the obvious advantages of drifting the drill pipe in a definite direction is the increased penetration of the oil-producing sand that becomes possible. Where high gas/oil ratios are encountered at the top of the crest of the producing formations, drifting the string down dip may result in a much lower gas/oil ratio well being completed.

Other possibilities for increasing the range of production of a well or for decreasing the difficulties and costs of drilling will readily present themselves, but sufficient has been written to show the advantages to be obtained by the perfection of a system which has been designated 'Directed Drilling'.

The actual drilling of directed holes does not differ in any way from that carried out for straight-hole drilling from the standpoint of surface equipment. The drill pipe is rotated at the surface by means of some kind of rotary table, and circulating fluid is pumped down the drill pipe to carry out its normal functions in the well. The subsurface equipment is, however, different in some respects from that normally used in straight-hole drilling.

A brief examination of the standard method of drilling will show that the bit is rotated with a certain amount of weight permitted to bear on the formation. The rotation of the bit coupled with this weight enables the hole to be drilled, and under normal conditions the steering of the bit is accomplished by regulating the weight together with the action of the pressure exerted by the mud fluid. Only where the hole deviates unduly are the various tools, used in directed drilling, utilized. The difficulty of steering the bit in straight-hole drilling will indicate the care that is needed to steer the bit in directed drilling and the amount of thought that has been concentrated on developing tools to ensure the deviation of the bit in the desired direction.


Fig. 1


Fig. 2


Fig. 3

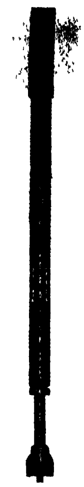
Fig. 4


Fig. 5

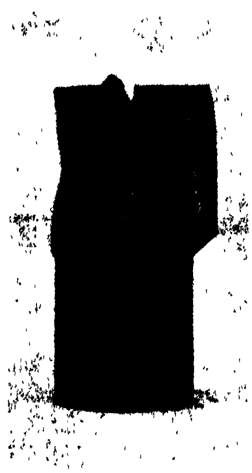
Fig. 6

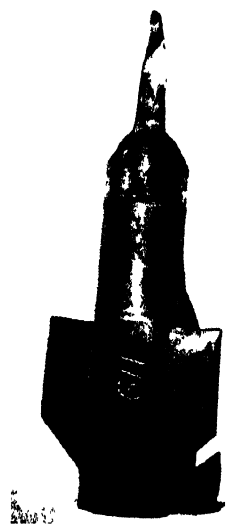
Fig. 7

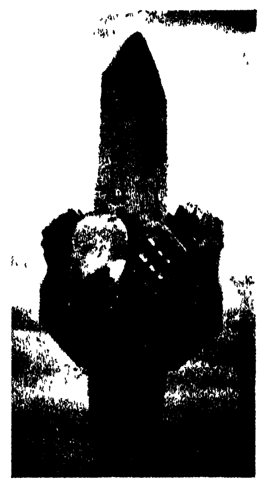
Fig. 8


Fig. 9

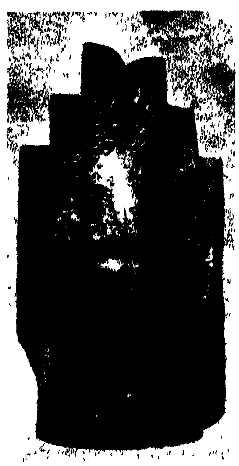
Fig. 10

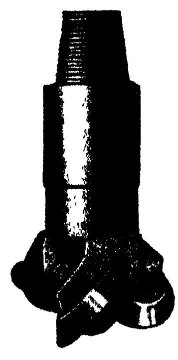
Fig. 11

Interest in directed drilling was manifested by the drilling of a relief well in the Conroe field of the Gulf Coast area in 1933, to enable water to be pumped into the formation to obtain control of a well that had got out of hand. This cratered producer was brought under control by drifting the relief well from a point 412 ft. from the crater at the surface, to a point as near as possible to the bottom of the producing well, and water was then pumped into the formation until the flow at the surface ceased. The effect of drilling this relief well has focused attention on the possibilities of directed drilling. Operators whose leases are in inaccessible positions, have therefore turned to this practice as a means of reducing their drilling costs and as an assurance that prolific producing areas can be tapped from locations which, if used for straight holes, would result in dry holes or, at best, small producers.

A realization of the fact that extraneous conditions in the well make the steering of the bit in a vertical direction a most difficult procedure will indicate the difficulties that must arise when the bit is to be directed to a definite point not immediately below the starting-point. This being so, additional equipment is needed to assist the driller to land his bit at the desired point.

The practice of directed drilling may be divided into two operations. The first of these is the practice of surveying the well by means of some type of directional-surveying instrument obtaining a reliable log of the well, giving both the direction and deviation at the moment the record is taken.

The art of surveying wells is not by any means a new one, for it was practised as far back as 1908 in the Rand of South Africa for holes drilled to depths of 4,000 ft. Since that time improvements have been made in these instruments and reliable records are now possible.

Any type of surveying instrument which will record the deviation and direction with accuracy can be used, but the most popular instruments may be divided into two types. The multiple-shot or intermittent-recording type and the single-shot or simple-recording type. All these instruments are photographic in their recording, the multiple-shot recordings being made on a motion-picture film whilst the single-shot record is made on a photographic disc 1½ in. in diameter. Where recordings are to be made in cased or partially cased wells the magnetic readings are not used and the drill pipe and instrument are oriented as they are lowered into the well. These instruments and the methods of orienting will be dealt with elsewhere as they do not come within the scope of this section.

Throughout the course of the well, whilst drifting the bit, surveys must be carried out, and the amount of hole drilled between each run of the surveying instrument will depend entirely upon the amount of drift desired and upon the opinion of the operator. The surveys should preferably be made at intervals of 50 ft., although under some circumstances it may be sufficient to carry them out at intervals of 100 ft. Where the distance between successive surveys exceeds 150 ft. the results obtained may not be sufficiently precise.

The first necessity of directed drilling is thus to be cognizant of the direction in which the bit is moving at all times, and for this to be possible some kind of surveying instrument must be run at predetermined intervals. It is obvious that the running of a surveying instrument cannot in any way assist in maintaining the hole on its proper course, except to indicate that it has or has not deviated from it, and other tools must be used to direct the bit along the desired course.

The second operation concerns, therefore, the actual deviation of the hole by means of special tools.

Drill holes may assume one of four forms: vertical, inclined, curved, and crooked.

The vertical hole is a rarity even when the bit is directed, and the crooked hole is definitely the most common. An effort to straighten a hole that has deviated may quite easily result in the drilling of a crooked hole. Naturally, this type of hole should be prevented on every occasion where possible.

The inclined and curved types of holes are aimed at in directional drilling, and the latter type is the more popular. To drill an inclined hole should be as difficult as drilling a vertical hole since in both cases the bit has to be steered along a straight course. The fact that the direction of the hole is at an angle to the vertical may, in fact, increase the difficulties of drilling, since there will be a tendency for the bit to hang to the lower side of the hole and for the hole to endeavour to follow a more vertical course.

The most general type of hole aimed at in directional drilling, is, therefore, the curved type, and in order that this may be attained numerous tools have been developed.

The most important of these tools is the whipstock. This tool has long been used in straight-hole drilling when circumstances in the well necessitated the sidetracking of lost tools. By its use the drilling bit is guided past the top of the lost tools and, provided the weight on the bit is adjusted properly and the angle of the face of the whipstock is correct, the bit is found to return to the vertical after the effect of the whipstock has passed. The effect of the whipstock is purely local and merely assists as a shield to the lost tools, enabling the hole to be drilled deeper without the necessity for skidding the rig.

Obviously the tool used to deflect the bit past a lost string could be of no value in directed drilling since it would have to remain in the hole once its duty had been performed, and a removable whipstock, that is, one that could be pulled from the hole when it had completed its guiding work, has been developed. Two types of this whipstock are available: a removable circulating type, Fig. 1, and a removable non-circulating type, Fig. 2. There is no reason why the effect produced when using the non-removable whipstock should not occur when using the removable type, but continual use of the tool would enable the hole to travel along the path of an arc, always provided that no extraneous conditions occurred to cause the bit to deviate in some other direction. That such extraneous conditions may arise must definitely be considered when examining the question of rotary drilling, and if the bit is once forced to leave its correct path and the conditions causing this deviation are not removed there would appear to be no reason why such deviation should not recur. These extraneous conditions have been referred to previously in the four critical factors. If, for example, the critical factor causing deviation is too great a weight on the bit, a reduction of the weight would permit the bit to travel in a different direction.

In form the whipstock is a tapered casting, thickening towards the lower end and equipped at the bottom with either a chisel, rotary shoe, or 'T' three-point footpiece. A tapered cavity is cast in the face of the tool down which the drilling-bit may slide, and at its upper end a stout ring or collar is forged, by means of which the tool may be withdrawn from the hole. Slight variations occur in these tools, such as the placing of hard rubber rings on the concave face through which the external flush-joint drill pipe works, but

the function of the tool remains the same. In practice the drill pipe is threaded through the ring at the top of the whipstock and a special bit made up larger than the hole in the ring. Two or three studs are inserted through the collar into the tool-joint above the bit to prevent rotation of the whipstock whilst going into the hole. The tool is then oriented into the well and the foot-piece dropped hard into the formation to obtain sufficient penetration to prevent its rotation. Immediately rotation is prevented the studs are sheared off by allowing the weight of the string to be exerted upon them and drilling can commence.

The length of drill pipe passing through the ring of the whipstock will depend upon the opinion of the operator, but in directional work, where a number of whipstocks need to be set, it has been found most practical to use a double length of drill pipe. This reduces the sidetrack drilling time and permits the whipstock to act as a guide over a greater distance. The drilling-bit used is of a smaller diameter than the desired diameter of the finished hole, and the hole is deviated in the given direction by virtue of the fact that the bit is forced into the formation by the face of the whipstock. The small diameter hole is drilled for the required distance below the whipstock and the tools are then removed by raising the drill pipe, allowing the collar of the bit, which is larger than the ring on the whipstock, to bear against the ring.

The hole is then reamed out to its correct size by the use of a larger diameter fishtail bit.

A number of special bits have been developed for use with the whipstock. For sidetracking in soft formations a bit equipped with spirals, which tend to force the bit away from the concavity in the whipstock, is used. For hard formations a rock-bit of the general form is utilized.

The need for using a number of whipstocks in medium-soft formations may not necessarily arise, as an accurate variation of the weight on the bit should suffice, but any change in the formations or in relative hardness would definitely compel the running of further tools.

A tool which permits deflecting without the use of whipstocks is the knuckle joint, Fig. 3. This tool is equipped with a universal joint, spring controlled to retain the portion below the joint at the desired angle. Mounted on this lower portion is a reamer, and the lower end terminates in a diamond-point or rotary-shoe bit. The upper portion is connected to the drilling string and circulation is carried through the universal joint to the bit.

This tool is oriented into the well with the drilling portion set at the desired angle. Before the tool reaches bottom the pumps are started, and on contact with the formation considerable weight is applied, causing the string to angle at the universal joint and to lean against the wall of the well. By allowing an excess of weight on the bit the string of drill pipe is started in the desired direction.

Another tool of this type is the spinning spudder, Fig. 4, which operates on the principle of the automatic screwdriver. No rotation of the drill pipe is needed for the operation of the spudder and with the table locked the pipe is merely raised and lowered. On each lowering, the bit revolves 2½ times, drilling the hole in the direction in which the elbow is faced.

In very soft formations, where other tools offer difficulties in deflecting, a hydraulicking spudding bit, Fig. 5, is used. This tool is oriented to bottom, any torque that may have built up in the pipe is removed, and the rotary table is then locked. The bit is lowered to the formation and the pumps started, and hole is made by the jetting action of the fluid operating against the curved upper face of the bit and being forced against the walls of the hole. The spoon shape of the bit allows it to slide off in the direction of the flushing action, and assistance is given to the sliding action by the aid of two wheels set in the back of the bit. Only a few feet of hole is made with this bit and the formation must obviously be of a very soft nature. Once the desired angle has been obtained, a drilling bit of the correct size can be run.

A large number of different types of bits have been developed and each one has a distinctive use and place in the practice of controlled drilling. These bits are used generally after the whipstock bit has completed its work, and only in special circumstances. Where conditions are more or less stable, a conventional-type bit may be used with success.

Many of these bits have resulted from a careful study and observation of numerous experimental types.

As a result of observations it has been found that different types of bits have definite tendencies in deflecting. When a drag-type bit is used the hole will generally go to the right, whilst the wheel-type bit causes the hole to turn to the left. Where rock bits are used the tendency is for the wells to turn to the left. Thus it should be possible to deflect a hole in any desired direction by selecting a bit possessing the tendency to turn in that direction. Unfortunately nothing definite can be stated regarding the direction in which these bits will deviate, and since this is so the possibility of a drag bit moving to the left or a wheel-type bit turning to the right, when these have been used to deflect a hole into the direction expected, must not be overlooked. In addition the possibility of the conditions, referred to previously, existing in the hole at the time of drilling must not be ignored and these will definitely affect the direction taken by the bit.

The special bits used in controlled directional drilling may be listed as follows:

1. Follow-up bit.
2. Pilot-reaming bits for soft and hard formations.
3. Spoon-bill bit.
4. Pineapple bit.
5. Disk bit.

In the follow-up type of bit, Fig. 6, are incorporated those features found to be most advantageous, namely, ability to carry weight without excessive penetration, stability in a directional sense, and freedom from excessive balling up. It is used to follow the whipstock bit and is usually run on a section of small drill pipe to assist it to build up the angle initially started by the whipstock bit. The amount of hole drilled with this bit will depend upon the length of the small diameter pipe used, the position of the kelly, and upon the length of the whipstock being sufficient to enable the whole of the kelly to be pulled up should it become necessary to set another whipstock.

The second type of bit, Fig. 7, whether for soft or hard formations, is used to ream out the deflected hole to gauge. Extending for a distance of 21 in. below the reamer is a pilot bit dressed either to a diamond-point or, for certain circumstances, to a dull point. The holes for the circulating fluid do not extend to the pilot bit, but washing is carried out by the fluid passing down the reamer blades. Before commencing to drill with this bit the pilot bit must have entered the hole made by the original deflecting bit and care must be taken to ensure that this has actually taken place. Careful rotation of the pipe at the surface will give this necessary evidence.

The pilot-reaming bit for hard formations, Fig. 8, is

equipped with rollers, on the peripheries of which teeth have been machined. This bit is used to follow up when a rock bit has been used to obtain the deflexion from the whipstock.

The spoon-bill bit, Fig. 9, is also run on a length of small diameter pipe and its special construction lends itself to the application of weight during drilling. It shows a tendency to form a left-hand turn and this is usually accompanied by a loss in drift angle. An increase in drift angle prevents the development of the left-hand turn.

The fourth class of bit, the pineapple bit, Fig. 10, has been found to build up drift angle, particularly when the bit is attached immediately below a three-point conventional reamer.

The most consistent bit for generating left-hand turn is the disk bit, Fig. 11. The angle at which the cutters are set probably increases the ease with which the turn is made.

No specific result can be depended upon when running either the spoon-bill bit, the pineapple bit, or the disk bit, but when run under the best possible conditions, with weight and speed adjusted correctly, economy can be shown in the drilling of the deflected hole.

Various types of whipstocks are available for use, depending upon the type of job to be performed. Such jobs may consist of straightening crooked holes, sidetracking lost materials or plugs, or directing the bit to a predetermined position below the surface.

In all these cases whipstocks will be found to be of value, although in the case of straightening crooked holes it may be possible to plug back to a straight portion of the hole and to redrill. It must not be forgotten, however, that, under certain circumstances, the conditions which caused the original deviation may still be existing, and the possibility of further deviation cannot be ignored. Should such a condition arise it will be necessary for a whipstock to be run to enable the deflecting forces to be overcome.

A removable whipstock will prove a decided advantage in straightening crooked holes, and on completion of its work it can be removed from the hole, to be used at some future time should this become necessary.

For sidetracking lost material it has been found possible to sidetrack by using a diamond-pointed bit, without the necessity of running a whipstock or of plugging with cement above the lost tools. In many cases of this sort, however, the lost material has fallen into the hole after the bit has passed, increasing thereby the difficulties. Where a whipstock is run the lost material is anchored by a small cement plug and there is no danger of falling in such circumstances. The use of whipstocks for directional drilling has been referred to previously. Great strides are being made in the practice of directional drilling and new tools are being devised to speed up directional operations and so increase the economy with which the job is carried out.

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ROTARY DRILLING FLUIDS

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IT is only recently that petroleum technologists have had a full appreciation of the importance of adequate control by chemico-physical means of rotary drilling in the technique of boring oil-wells. Any drilling fluid may be regarded as a system of three main constituents, as follows: water, colloidal matter, consisting of both gel-forming and non-gel-forming colloids, and larger particles suspended in the medium. Of the two types of colloid present, the gel-forming type is definitely the more important, for this group imparts the necessary properties of an efficient drilling fluid, i.e. stability of suspension, viscosity, pore-sealing, and gel characteristics in general. Colloids of the non-gelling type, together with larger particles, contribute somewhat to viscosity, but more particularly to the density of the drilling fluid. Adequate control is a problem of colloid chemistry, and it will be shown how the colloids present respond to treatment, giving desirable and necessary characteristics of drilling fluid, modified, of course, by the inert material always present.

I. Application of Rotary Drilling Fluids

Drilling fluids perform several distinct functions in the drilling of a well. The first, and elementary purpose, is to lubricate and cool the bit during drilling, at the same time furnishing a medium that will mix with the cuttings, allowing them to be readily removed; in cable-tool drilling this function may be performed by a short column (30 ft. or so) of muddy water. A mud that is slightly plastic or gelatinous will suspend the cuttings satisfactorily, allowing them to be picked up readily in a bailer.

For rotary drilling purposes the requirements for a drilling fluid are more complex. Besides lubricating and cooling the bit, the drilling fluid must carry cuttings to the surface and deposit them in the slush pits. Cuttings should be released as completely as possible to prevent damage to the liners and valves of the mud pumps. If the fluid in the hole contains an overburden of cuttings, these may settle out and 'freeze' the bit when drilling is stopped.

The drilling fluid should seal off water sands, minor oil and gas sands and soluble mineral deposits, prevent heaving and caving of the walls, and prevent pollution of oil and gas sands by water or mud.

The drilling fluid should prevent blow-outs due to high-pressure gas, by furnishing the required hydrostatic head against the gas-bearing strata. Gas-bubbles must be released at the surface, in order that the fluid column may not be lightened by an increasing burden of gas-bubbles.

As a result of wide variations in local structural conditions, requirements differ considerably not only from one oilfield to another, but also from well to well in the same field. For example, drilling through limestone often presents the difficulty of loss of fluid in cavernous structures, but no caving or heaving will occur, as in some shale strata, where loss of returns is practically unknown. In the two cases, the requirements for the proper drilling fluid are widely variant.

The more important applications of drilling fluids will be considered separately, with discussion of the specific functions required and how they may be fulfilled.

Carrying Cuttings.

Water can be, and has been, used in the rotary drilling of wells. To carry cuttings to the surface the water must have sufficient velocity to carry the smaller cuttings; larger cuttings will be ground up by the drill. In turbulent flow the velocity of slip between a cutting and water is given by Rittinger's formula:

$$v_s = 7{\cdot}1\left(\frac{d(\rho_1-\rho_2)}{\rho_2}\right)^{1/2}$$

where v_s = velocity of slip in ft. per sec.,
d = diameter of cutting in ft.,
ρ_1 = density of cutting in lb. per cu. ft.,
and ρ_2 = density of water in lb. per cu. ft.

The constant 7·1 becomes about 5·2 for flat particles. For a round particle 0·01 ft. in diameter and of specific gravity 2·5, v_s equals 0·87 ft. per sec., approximately the minimum vertical velocity that must be maintained just to prevent the particles from settling in the column of water. In a 4-in. hole the volume of water that must be pumped to remove cuttings of this size will be in excess of

$$0{\cdot}87\pi\times(\tfrac{1}{6})^2\times 60 = 4{\cdot}55 \text{ cu. ft. per min.}$$

For flat particles a considerably lower fluid velocity is required. A limited discussion of carrying capacity has been given by Bignell [8, 1930].

A study of the carrying capacities of drilling fluids is complicated by their abnormal fluid properties. The viscosity of a drilling mud decreases with the rate of shear and, therefore, in a pipe of constant radius, with its linear velocity. The settling of particles of greater than colloid size is hindered by the pseudo-plastic nature of muds containing colloids. Although no data are available, it is generally known that cuttings settle at a relatively low rate in a clay mud, and that low fluid velocities will pick up and carry cuttings satisfactorily. Where caving and heaving occur, forcing large pieces of formation into the bore-hole, high fluid velocities are required to remove them. The carrying capacity of drilling fluids has not been considered of sufficient importance to demand extensive research.

The Release of Cuttings.

Release of cuttings [25, 1932] is an important function of the drilling fluid. In drilling an 8-in. hole, approximately 0·35 cu. ft. of cuttings are added to the mud per foot of depth. If the formation is shale, clay, or gumbo, increased viscosity of the fluid by dispersion of small particles may require dilution by water. The harder and larger mineral cuttings must be removed by settling in order to prevent 'freezing' of the drill, when drilling is stopped, and to prevent scoring of the pump.

Round particles in a normal fluid settle in accordance with Stokes' Law:

$$V = \frac{2gr^2(\rho_1-\rho_2)}{9\mu},$$

where V = velocity of settling of a particle of radius r, and density ρ_1, in a fluid of density ρ_2, and viscosity μ; g is the

gravitational constant. It is clear that settling is more rapid in the less viscous fluids. This is true even for drilling fluids which show the property of thixotropy. Most drilling fluids containing clay are reversibly thixotropic: when subjected to mechanical agitation the gel is broken and the viscosity is decreased; on returning to quiescence the gel is re-formed and the apparent viscosity is enormously increased. This property of gelation, and high viscosity at low rates of shear, accounts for the retention by a mud of particles of greater than colloidal size. A mud having a definite yield-point, or minimum shearing stress that must be applied before motion is initiated, will retain in suspension those particles not sufficiently large to furnish the yield-point shearing stress. However, no quantitative data on the relation between yield-points and the retention of cuttings are available.

The above discussion indicates that the proper conditions for a drilling fluid that will release cuttings in the proper places (the settling troughs, or slush pits) are that

(1) The drilling fluid will gel quickly in the hole when drilling is stopped, to prevent settling of cuttings around the drill.

(2) The drilling fluid will have a low viscosity and will not be in the gelled condition during flow through the settling troughs and slush pits.

Data on the viscosities of drilling fluids show that the viscosity reaches a minimum value at rates of flow just short of turbulence. It is therefore desirable to maintain flow just short of turbulent in the troughs; this requirement is aided by flowing the drilling fluid over and around baffles at a fairly rapid rate. It is also desirable to maintain motion in the slush pits to prevent gelation.

The apparent viscosities of drilling fluids may be lowered by addition of chemicals, as shown in Fig. 1 [2, 1931]. The salts of strong bases and weak acids, such as tannic acid and humic acid, cause remarkable lowering of viscosity.

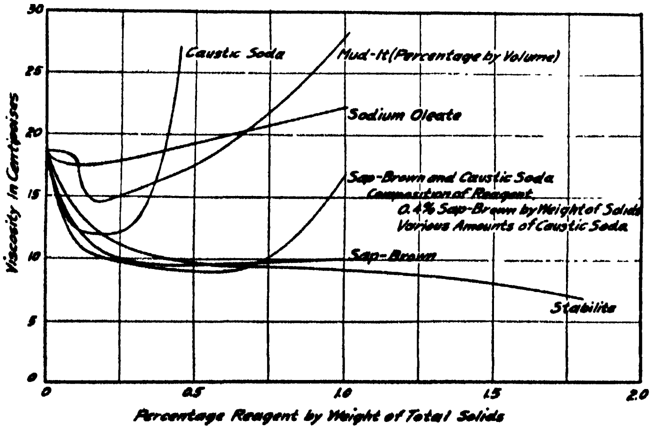

FIG. 1. Pierce Junction mud fluid treated with various chemical reagents. Viscosity plotted against percentage reagent by weight of solids. Temperature 25° C.

Caustic soda alone causes an initial lowering of viscosity, followed by an increase as the colloids are flocculated.

Fig. 2 [3, 1933] shows the effect of such chemicals on the sieve analyses of clay muds before and after treatment with chemicals. The points at the left of each graph indicate the percentages of each particle size in suspension before treatment, and the points at the right the sieve analysis after treatment. It is important to mention that all particles larger than 200-mesh settled out in the first 10–15 minutes after treatment, while particles between 200-

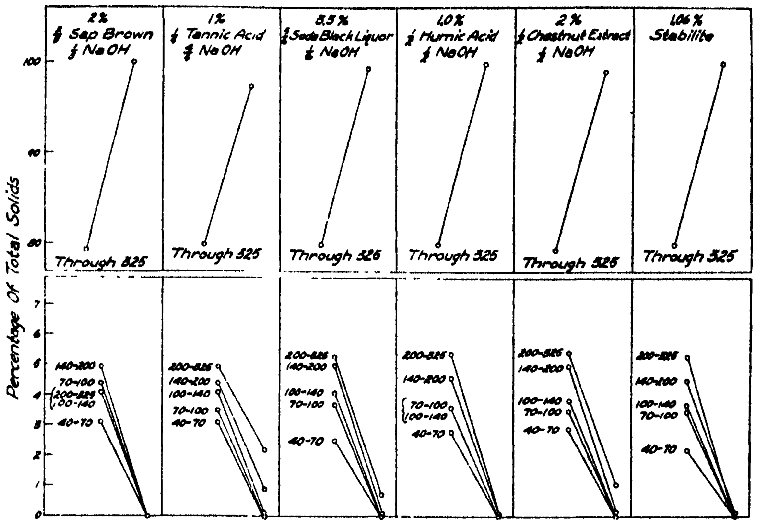

FIG. 2. Sieve analyses of muds before and after treatment.

and 325-mesh settled gradually over a 24-hour period. It is evident that the particles larger than 325-mesh were selectively settled, leaving the colloids in suspension. The extent of separation may be varied by variation in the amounts and type of chemical employed.

Stabilite is an example of a commercial chemical of this type. Mixtures of quebracho and caustic soda have been successfully used in conditioning drilling fluids in deep-well drilling. Such chemicals should be used under skilled supervision, and not added to a drilling fluid without previous experiment as to what the result will be.

Rate of Settling.

One of the most desirable properties of a drilling fluid is the stability of the suspension. When circulation of fluid is stopped it is desirable that the solid content remain in suspension, not settling around the drill stem to bridge or freeze the drill. The mud in reserve pits should be ready for immediate use, which is not possible if rapid settling allows caking of settled material; the entire body of mud should remain fluid.

Rates of settling may be measured in several ways as follows: (1) rate of formation of free water above the sludge, (2) rate of increase of solid content below a reference mark, (3) accelerated settling by centrifuging. Either (1) or (2) is applicable in measuring the rate by this method.

Method (1) is applicable only for a measure of formation of free water, but not for a measurement of true rates of settling except when the particles are uniform in size and all have equal rates of settling, as shown by Ambrose and Loomis [4, 1933]. True rates of settling may be obtained by method (2) where the amount of material passing a reference mark per unit time is measured. In a case where the height of sludge was used as a measure of the amount settled, the results showed 100% in suspension at the end of 24 hours, whereas actually only 25% of the original suspended solids were

in suspension. Colloid particles of clay may be held up for some time, while larger non-colloids settle very rapidly.

Centrifugal methods are valuable when rapid comparative tests are desired; 50-ml. samples are satisfactory for the purpose. At regular intervals the amount of solids below a certain reference point, 10 ml., for example, may be measured for solid content by removal, drying, and weighing, discarding the upper 40 ml.

Convenient settling measurements may be made in a series of glass tubes, 3·5 cm. in diameter, 45 cm. in length, with a reference mark at 20 cm. from the bottom. After a given time the liquid is removed to the reference mark, and percentages of solids settled past this point are determined by calculation, using the initial and final densities of the lower portion. Space does not permit development of the simple equations required for the calculation; the only error is due to variations in densities of solids present. Where these variations are large, it is well to measure the percentage increase in the lower portion by drying and weighing the samples. From the original average composition of the mud the percentage of solids settled from the upper portion may readily be calculated.

An early paper by Parsons [34, 1930] suggested a satisfactory criterion of stability, describing an ideal drilling fluid, in part, as one 'that will not settle more than 2 per cent. in 24 hours'. Qualitatively, it has been found that such a drilling fluid does not cake in the mud pits, remains sufficiently fluid for instant use over a considerable period, and will not give dangerous settling when circulation is stopped for some hours.

The rate of settling of a drilling fluid is dependent upon its viscosity, plasticity, colloid content, the sizes of particles present, and the density of the fluid itself. Settling is greatly retarded by the presence of materials that impart to the fluid a high static viscosity, or a viscosity that is great at low rates of shear and low shearing stresses. A plastic drilling fluid, or one having an actual yield value, has high stability because of its innate resistance to motion.

Penetration and Sealing of Walls.

It is well recognized that a drilling fluid should properly seal the walls of a well to prevent pollution of strata containing valuable mineral deposits; to prevent loss of fluid from the hole when costly materials are contained therein or when loss of fluid may lower the fluid-level where gas-cutting may occur. Knapp [24, 1923] has shown that clay-bearing drilling fluids will effectively seal the walls under ordinary circumstances.

Quantitative measurements by the authors and others have shown that the penetration of drilling fluid under pressure into sands and unfractured sandstones is slight, the penetration being of the order of magnitude of $\frac{1}{16}$ to $\frac{1}{2}$ in., depending upon the size of the sand grains. When a clay mud is forced under pressure against a sand-face, in a few seconds the flow of slightly muddy water ceases, the water becomes clear, and flow entirely ceases as an impervious filter-pack is formed. The following table shows the penetration of mud and water, and the depth of the filter-pack when mud was forced into sands under pressure of 50 lb. gauge:

Screen analysis of sand	*Water penetration*	*Clay penetration*	*Depth of filter-pack*
mesh	in.	in.	in.
35–50	12	12	1/16
80–120	$1\frac{1}{2}$	1/16	1/16
150–70	$1\frac{1}{4}$	1/16	1/16

The mud sample weighed 10·4 lb. per gallon, and was from Seminole, Oklahoma.

Bentonitic muds showed higher penetrations of solids because of the preponderance of particles approaching colloidal dimensions.

Further tests were made by forcing mud under 500 lb. pressure into samples of Buff Mountain sandstone. In all cases penetration was slight and flow ceased within a few seconds after application of pressure. In no case was the pressure necessary to rupture the filter-pack by reverse flow greater than 7 lb. gauge. Qualitatively it may be said that penetration is diminished by the presence of sand, cuttings, or large particles; penetration is less for the more viscous and plastic muds.

Relation of Mud Fluids to Completion.

The above discussion does not indicate the deleterious effect that mud penetration may have on an oil or gas sand. Rubel [36, 1932; 37, 1932] has demonstrated that it is perfectly possible and highly probable that the potential rate of production of a well may be decreased by lodging of solids from the mud in the producing sand.

The mechanism of plugging may be explained by a simple case. The permeability of a sand core is highly sensitive. If tap-water, or even distilled water, is flowed through a core of low permeability at constant pressure, the rate of flow decreases with time, due to deposition of dust and solids produced by hydrolysis of the glass container. In Botset's [12, 1931] laboratory measurement of permeabilities it has been found necessary to pre-filter distilled water to prevent plugging of core samples.

The probability is great that mud solids deposited in an oil stratum greatly reduce the production below what it would be if the solids were absent. It has been found that plugging is only partially removed by reversal of flow. Statements by geologists, that many oil sands have been missed in rotary drilling because they were mudded off, are probably very true.

Miller and Shea's publication [29, 1934] suggests a method for removing such plugging by acid treatment of the well as soon as drilling is completed. Current methods of removing mud from the producing strata are largely hydraulic or mechanical, and probably fail to remove mud that has penetrated and lodged within the sand.

The newly proposed method of completion presents the advantage that solids that have infiltrated into the producing formation are partially dissolved by acid and dislodged by mechanical action of carbon dioxide gas generated by the reaction. Miller and Shea propose the addition of 20 to 30 lb. of pulverized calcium carbonate per barrel of drilling fluid used for completion, followed by acid treatment. It would probably be advantageous to use such a mixture for the actual process of 'drilling in'. The use of substantially complete calcium carbonate mud is also feasible. Pulverized lime, such as that obtained from finely ground oyster shells, may be stabilized with a small percentage of bentonite. Complete substitution of calcium carbonate for clay has the advantage that the mud is almost completely soluble in hydrochloric acid. When some clay is used, solution of the clogging particles will not be complete, and the optimum advantage will not be gained by acid treatment.

The proposed use of oil as a drilling fluid in completing oil-wells has not become general, although it possesses some theoretical advantage. A disadvantage rests in the fact that circulation of oil would pick up clay from the

walls of the hole, possibly carrying some into the pay sands in the usual way.

It is highly possible that the column of muddy water standing in the hole during completion of wells by cable tools may cause some plugging. There are no data available on this point, but the acid treatment of all wells, as a routine procedure, following the use of a limestone mud for drilling in, particularly in other than limestone formations, seems to be highly advisable. As yet a sufficient number of comparative test results are not available for publication.

Relation of Drilling Fluids to Heaving Shale.

Since a full discussion of the locations of heaving shales and of various methods of drilling these formations may be found elsewhere [30, 1934; 31, 1933], this discussion will be limited to various methods of combating 'heaving' by drilling fluids.

There are at least two distinct conceptions regarding the mechanism of heaving. According to some authorities, heaving is a purely mechanical action. It may occur by sloughing of tilted (non-horizontal) bodies of shale, due either to pressure of the overburden or to internal stress. It is fairly generally believed that horizontal beds of shale do not heave, cave, or slough badly during drilling. The fact that severe heaving often occurs on the flanks of salt-domes, where the salt plugs have distorted the shale strata, such as the Jackson shale (Gulf Coast), upholds this view. Drilling under pressure has failed to solve the problem, but the pressure exerted by the stresses within the shale may be in excess of those available with common drilling technique.

On the other hand, wide consideration has been accorded the view that shale heaves by expansion and sloughing following absorption of water. It has been shown by analysis that shales contain relatively high percentages of soluble salts. There is a tendency for water to pass from drilling fluid of low salt content into the shale, similar to the passage of water through a semi-permeable membrane, to dilute a salt solution on the other side. Theoretically, a very large solution pressure may be built up in this way, causing expansion of the shale with attendant sloughing into the hole. A dry piece of Jackson shale immediately disintegrates when placed in fresh-water, but will remain intact for a considerable period in a saturated calcium chloride solution. Davis [15, 1928] has shown that dialysed bentonite (containing no salts) does not swell or absorb water, but common bentonites, containing soluble salts, swell with production of considerable pressure. Clays also have the characteristics of swelling in water. The use of salt solutions for drilling through heaving shales has failed, largely because of failure in carrying out cuttings and large pieces of shale. The use of drilling fluids saturated with salts is the subject of a patent [27, 1931] which has not yet been thoroughly tested in practice. The method was designed as a prevention of heaving rather than a cure. The specific purpose of the method is to keep water from the shale. The method has been successfully used in drilling through the Sylvan shale in Oklahoma, using cable tools.

Bentonite drilling fluids have been tested for the purpose, the idea being that the drilling fluid would retain water due to its high affinity for water rather than allowing it to pass to the shale. The tendency for water to enter the shale would not be appreciably reduced by the bentonite, however. If there is any truth in the theory that water causes disintegration of the shale, it is probable that a drilling fluid of high solid content should be used in order to form a 'filter-pack' impervious to water.

Various chemical reagents have been used to combat heaving shale, most noteworthy, perhaps, being mixtures containing caustic soda and tannic acid to lower the viscosity of the drilling fluid. This allows high fluid velocity and rapid release of cuttings in the slush pits; but in opposition to this, drilling fluids of low fluid velocity with high viscosity have been advocated by some authorities. Sodium tannate is said to make shale sticky and plastic, making it rigid rather than prone to crumble or slough [1, 1933].

Drilling with oil has been suggested as a method suitable for prevention of the deleterious action of water on shale, but the method has not been adopted; high fluid velocities would be necessary to carry out large cuttings, but this difficulty does not seem prohibitive.

Freezing has also been suggested, but not yet tried. The difficulties and expense of supplying sufficient refrigeration to freeze completely the walls of the hole during drilling do not seem to warrant trial of so doubtful a method. Chemical methods of freezing, or solidification such as are used in shutting off water and for cementing caving sands, might have some application, but have not been tested on heaving shales. Alternate treatments of sodium silicate solution and inhibited hydrochloric acid might be used for the purpose, the silicic acid produced in this way having binding and sealing properties. In other words, there is the possibility of cementing the shale together by chemical means. The main difficulty would probably arise from poor penetration by the sealing solution. The heaving-shale problem is particularly suitable for those chemists and engineers who have access to drilling wells on which they may experiment. The problem has been barely scratched at the surface to judge from the results so far obtained in field practice. However, a broad view should be taken, remembering that the heaving may be purely mechanical or that it may be a result of both chemical and physical processes.

Gas-cutting of Rotary Drilling Muds.

Gas-cutting of drilling fluids has been one of the most important problems in this field, because of the large expense and the drilling difficulties incurred. The phenomenon is more readily explained than defined. Gas-cutting may occur during drilling into a horizon containing high-pressure gas, that is, gas where pressure is near to, or above, that required by the theoretical hydrostatic head of water at that depth. Gas is soluble in water, and its solubility is approximately proportional to the pressure of the gas. According to Frölich [19, 1931], methane is soluble to the extent of about 3 volumes of gas (measured at atmospheric pressure and 60° F.) per volume of water at 1,470 lb. per sq. in. pressure, and 88° F. Gas may enter the drilling fluid by direct solution or by bubbling into the column of drilling fluid. As the fluid rises in the hole the pressure decreases, and gas comes from solution and expands, the dispersion of gas-bubbles in the fluid becoming progressively worse. The fluid is lightened by bubbles, decreasing its specific gravity.

A blow-out occurs if the drilling fluid becomes so light that the pressure against the gas horizon, as furnished by the fluid column, decreases to a value equal to or less than the gas-pressure. For example, consider a well drilling at 1,000 ft. depth, encountering gas. The pressure of a column of water at that depth approximates 434 lb. per sq. in. (0·434 lb. per linear foot). If the gas-pressure is less than

434 lb., the column of water will hold it back in the sand, but if the pressure exceeds 434 lb., the gas must escape through the fluid column. If the sand is capable of delivering large volumes of gas, a blow-out will occur.

Although it has been argued that the pressure in a gas sand should not exceed the hydrostatic head of water, cases are known where this is not true. There have been many cases of high gas-pressure in comparatively shallow sands.

The main property required of a drilling fluid in a high-pressure gasfield is weight, or sufficiently high specific gravity. The minimum required fluid weight will be

$$W = \frac{8{\cdot}33P}{0{\cdot}434D},$$

where W = weight of drilling fluid in lb. per gallon,
P = pressure of gas in sand, in lb. per sq. in.,
D = depth of gas sand, in ft.

The earliest weighting material was clay. In many cases it will supply sufficient weight to serve the purpose. Occasionally, a saturated salt solution will have the required density. The common mud weighting materials now in use include mixtures containing barytes, iron oxide, or silica. The sale of weighting materials in the United States is somewhat limited by the Stroud [40, 1926] patents.

Although maintaining the drilling fluid at a high specific gravity aids considerably in reducing and preventing gas-cutting, other properties must be considered. Even when the hydrostatic pressure is theoretically more than sufficient, gas enters the fluid from cuttings drilled up by the bit, by diffusion from the sand, and by solution. Solubility of gas is not decreased by the column pressure which only holds the gas back in its stratum, preventing a blow-out, and hinders rapid motion of gas into the fluid. Gas diffusion is also hindered by the formation of a filter-pack or layer of mud solids on the walls of the hole. But usually some gas enters the fluid and must be released in slush pits, or it will be recycled, and the cumulative effect will eventually make gas-cutting severe.

The following properties of a drilling fluid favour ready release of gas:

(1) Low viscosity.
(2) Low plasticity; i.e. low yield-point.
(3) Freedom from oil.
(4) Low surface tension.

In an ordinary viscous fluid a gas-bubble rises approximately in accordance with Bond's [11, 1927] modification of Stokes' Law, the velocity of rise being approximately inversely proportional to the viscosity of the liquid. Most drilling fluids are not truly viscous, and the laws concerning the rise of bubbles are not definitely known. Being partly colloidal, drilling fluids do not have a viscosity that is a constant at constant temperature; the viscosity decreases with the rate of shear or flow velocity of the fluid. This property hinders the release of gas. Those fluids which gel and have a definite yield-point release gas very poorly. The yield-point may be so high that the bubble will not rise at all; it will not exceed the minimum pressure or stress required to start it in motion.

It often occurs that oil contamination may increase the difficulties of gas-cutting. Oil, emulsified in the drilling fluid, causes the formation of a tough film, and the bubbles do not readily break to release the gas. Oil dilution may be reduced by maintaining the fluid at its proper weight.

It may be shown that lowering the surface tension of a drilling fluid allows the formation of larger bubbles which are released more readily. This fact has been experimentally verified in the laboratory by the authors [5, 1935].

Several mechanical contrivances have been used in the field to assist in the release of gas from gas-cut drilling fluid [41, 1930; 42, 1930]. In general it has been found necessary to resort to mechanical treatment, if the fluid has the desired physical properties of low viscosity, low plasticity, and freedom from oil. Mechanical separation of gas was widely used in Hobbs, New Mexico [8, 1930], during the peak of drilling operations in 1930.

There are several points concerning the handling of weighted rotary drilling fluids that are of particular importance where gas-cutting may occur. The hole should be filled with fluid when the drill pipe is withdrawn, for the displacement may amount to 15% of the volume of fluid in the hole. Failure to replace the displaced volume will result in a 15% loss in fluid head on the sand, and is by no means as uncommon an oversight as might be supposed.

The weight of the drilling fluid should be carefully checked with calibrated instruments. The mud bucket and spring scale commonly used have been found to be as much as 25% in error. Of a number of such devices tested by the authors on drilling wells in a field where the gas-cutting was severe, the majority showed a positive error in measuring the density of drilling mud.

Sluices taking the discharge of drilling fluid from the well should have baffles and should be narrow enough to permit fairly rapid flow. The rate of flow should be just slightly short of turbulent in order that the fluid will be at its minimum viscosity, permitting more ready release of gas. Slush pits should be fairly shallow in order that the gas will have to travel but a short vertical distance to be released. It is desirable to maintain as much horizontal motion as possible in the slush pits to prevent gelling of the mud.

The common admixtures for weighting drilling fluids have been mentioned. It is not safe to add Baroid, iron oxide, or silica to clay or to bentonitic stabilizers such as Aquagel in any but predetermined proportions. Low plasticity and low viscosity require either low colloid content or the addition of chemicals. In general, the clay or bentonite content should be maintained at a minimum consistent with stability (low settling rate), for the colloid content of these materials increases both viscosity and plasticity. Chemicals such as sodium tannate solutions should also be used with caution, especially with weighted drilling fluids. Excessive amounts of actively alkaline or basic salts, acids, bases, or electrolytes greatly increase the rates of settling for solids.

The combinations of water, chemicals, clay, and weighting materials that may be used successfully for the purpose are so numerous as to prohibit enumeration here. Below will be found the general properties of typical fluids suitable for the purpose.

Only brief mention can be made of engineering precautions, which are fully considered elsewhere [20, 1933]. Steam-driven piston-type blow-out preventers are necessary equipment in some fields. When the gas seems to be getting out of control the preventer may be closed, and circulation continued under pressure until the fluid is partially or completely free from gas.

Weighting materials may be reclaimed by washing with water, allowing the solids to settle; the oil and water are drained off, and the layer of mud-laden fluid separated from cuttings. The fluid should be stored wet, preferably in

tanks. The high cost of weighting materials requires the utmost caution and care in handling, prevention of expensive and dangerous blow-outs, and prevention of oil dilution. The time and production lost in this way in a flush field incur enormous losses where the proper precautions are not observed in handling mud.

II. Physical Properties of Drilling Fluids

Colloidal Properties.

A number of practically important properties of drilling fluids are directly dependent upon the colloids contained therein. No simple means of measurement of the colloid content of a drilling fluid is known. We reason, therefore, by analogy that properties such as stability, or low rate of settling, from suspension, high apparent viscosity (relative to water), and viscosities that are varied by the conditions of measurements arise from the nature of the colloids present.

Varying definitions give the sizes of colloidal particles to be of the magnitude of $20\text{–}1{,}000 \times 10^{-8}$ cm. in diameter. It would be impractical to classify drilling fluids by their contents of particles of this order of magnitude. The sources and reactions of colloid particles suitable for use in drilling fluids are of more importance.

A drilling fluid has, in general, three components: water, colloids, and non-colloids or inert particles. There also may be present any number of dissolved constituents such as salts, and more or less inert organic matter. Additions of inorganic salts, acids, bases, and organic reagents produce remarkable results on the properties of the colloids, and, by influencing the colloids, on the drilling mud as a whole.

The colloids with which we are concerned are formed by subdivision of large aggregates into fine particles or dispersions. Mechanical methods, steaming, grinding, and stirring clays with water aid in accomplishing this result. Clays are actively hydrated when brought into contact with water, assisting not only in their dissolution or subdivision, but also in peptization or stabilization. Bentonite is an example of a mineral that can be hydrated to a remarkable extent and can be readily dispersed in water. Those minerals such as barytes, which are poorly hydrated and swell little or not at all in water, make poor colloidal suspensions, even with fine grinding. They require the addition of a hydrated colloid to give them stability in suspension.

The hydration of clays and bentonites is in large measure due to the presence of adsorbed salts; dialysed bentonites swell little and hydrate poorly with water [15, 1933]. The stability of colloids of the type including clays and bentonites is due to small quantities of adsorbed salts which, in water, are adsorbed as ions, imparting a definite and measurable charge to the individual particle. Since each particle has a like charge, they repel each other and tend to remain in suspension. If the charge is neutralized by addition of sufficient ions having an opposite charge, the particles are precipitated by neutralization or coagulated.

The effect of ion adsorption is illustrated in Fig. 3, from data by Ambrose and Loomis [2, 1931], where the effects of hydrochloric acid and sodium hydroxide on a suspension of 5% by weight of bentonite in water are shown. The samples were centrifuged at high speed for 5 hours and percentages of solids remaining in suspension measured. The untreated sample had a *pH* of 9, and points of maximum deflocculation (least settling) found both when treated with alkali to a *pH* of 11 and with acid to a *pH* of 5·5. Excessive addition of alkali caused flocculation as the adsorption of OH^- ion reached a maximum, followed by neutralization of the charges by further addition of the Na^+ ion. A similar effect was observed in acid solution where the H^+ ion was first adsorbed. When the electrokinetic potential is zero, or the potential between the

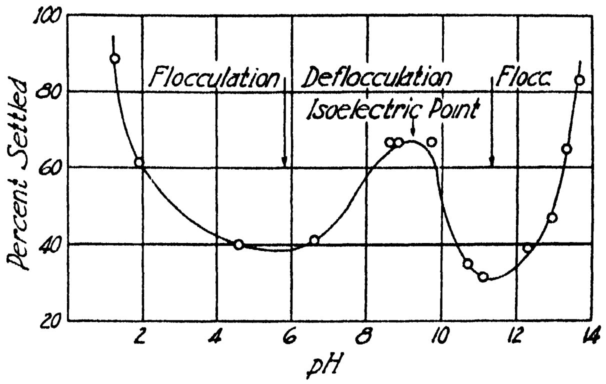

FIG. 3. Effect of *pH* on stability of bentonite suspension.

adsorbed layer of water and the main body of the liquid is zero, the particle is at the isoelectric point and will adsorb either positive or negative ions to increase its stability.

Very small quantities of inorganic salts aid in the deflocculation or stabilization of clays, but as the amount is increased and the flocculation value or critical point is reached, followed by complete coagulation or flocculation. Lack of stability in salt solutions requires that fresh water should be used, when possible, in making mud fluid.

Coagulation does not necessarily mean that the rate of settling will be increased beyond the allowable limit. Gelation may occur, leading to an enormous increase in viscosity, preventing rapid settling.

On the other hand, a gel is not necessarily a coagulated colloid, but may be formed by the addition of less than the amount of a salt required for coagulation.

Aqueous suspensions of bentonites, and to a less degree clays, exhibit the property of thixotropy. If a thixotropic gel is agitated, the material becomes quite fluid, but the gel is re-formed some time after agitation ceases. This property is largely accountable for the stabilizing effect exerted on inert admixtures such as barytes. The high static viscosity of the gel retards settling of the small particles held in suspension. A light gel is therefore desirable for drilling fluid that is not in motion.

By 'peptization' is meant the production of a colloidal state by suitable chemical or physical means other than mechanical methods. Soaps furnishing free hydroxyl ions by hydrolysis are fairly effective peptizing agents. Natural humic acids, occurring in clays, aid in their peptization. Alkaline solutions of tannin, humins, quebracho, and other similar organic acids may be used in treating drilling muds. According to Lawton, Ambrose, and Loomis [26, 1932] the proper mixtures of these materials with caustic alkali aid in stabilizing the colloid content of drilling fluids, while reducing their viscosities.

The divalent and trivalent metallic ions are able to exert a more pronounced precipitating effect on clays than the monovalent ions. Calcium, for example, as slaked lime may be added to a drilling fluid to increase its viscosity by coagulation, making a stiff mud for use when circulation is lost. Lime is not a stabilizing agent.

Space does not permit more than a very superficial glance

at the colloidal properties of drilling fluids. For a more comprehensive understanding of the subject, standard textbooks should be consulted.

Density or Specific Gravity.

The density of a drilling fluid or weight per unit volume is dependent upon the individual densities of the aqueous and solid contents. Defining the individual properties by the following terms:

W = weight of water per unit weight of drilling fluid,
C = „ solids „ „ „
D = density of drilling fluid, weight per unit volume,
d = „ solids, weight per unit volume,
d_1 = „ water, „ „
$W+C$ = total weight of sample,
$\frac{W}{d_1}+\frac{C}{d}$ = total volume of sample;

then
$$D = \frac{W+C}{\frac{W}{d_1}+\frac{C}{d}}.$$

If a drilling fluid contains 25% by weight of clay having a density of 2·5 and 75% pure water, the approximate density of the drilling fluid will be

$$D = \frac{0{\cdot}75+0{\cdot}25}{\frac{0{\cdot}75}{1}+\frac{0{\cdot}25}{2{\cdot}5}} = 1{\cdot}176.$$

Since the density of water is 1·0 at 4° C. and less at higher temperatures, corrections may be made for absolute densities. The specific gravity may be used in place of density, and is the ratio of the weight of unit volume of drilling fluid to weight of unit volume of water. Taking the density of water as 1·0000 at 4° C., the specific gravity of the above drilling fluid may be expressed as $1{\cdot}176\,\frac{25^\circ}{4^\circ}$, indicating that 1·176 is the weight of 1 ml. of the drilling fluid at 25° C. divided by the weight of 1 ml. of pure water at 4° C.

The above formula will be slightly in error if the solids contain adsorbed or occluded salts, for the volumes of salts and water are not additive; however, the formula is suitable for most practical purposes.

Densities of solids may be readily determined by weighing a known volume of a suspension in kerosine of a known weight of solids [17, 1931]. A pycnometer or specific gravity bottle is suitable.

Accurate measurement of the specific gravity of a drilling fluid is best accomplished by weighing a known volume of the fluid. Hydrometers are not suitable, particularly for the more viscous drilling fluids, because of their sluggishness in reaching equilibrium. For rough measurements in the field, the usual mud bucket and scales, weighing in pounds per cubic foot and pounds per gallon, are suitable if kept clean and frequently checked. Other mechanical weighing devices, including recording weighers, are available, as described by Kerr [22, 1932; 23, 1932].

Viscosity and Flow of Drilling Fluids.

The viscosity of a drilling fluid at constant temperature is not a single, unique constant as for an ordinary fluid. The viscosity of a drilling fluid, as for clay slips and many other similar fluids having colloidal properties, varies not only with temperature, but with the rate of shear and with the amount of agitation to which it has been subjected. It is a characteristic of drilling muds and similar fluids that the apparent viscosity decreases with increasing rates of flow. In considering flow through a tube or pipe the following terms may be used:

E = millilitres of fluid flowing per sec.,
R = radius of tube or pipe in cm.,
P = pressure drop between ends of tube in dynes,
L = length of tube in cm.,
μ = viscosity in poises.

Poiseuille's Law expresses the flow relationship in a tube as follows:

$$E = \frac{\pi R^4 P}{8L\mu}. \tag{1}$$

Expressing the equation in another way:

$$\frac{4E}{\pi R^3} = \frac{1}{\mu}\frac{PR}{2L}, \tag{2}$$

or
$$x = \frac{1}{\mu}S. \tag{3}$$

$$x = \frac{4E}{\pi R^3} = \text{rate of shear},$$

$$S = \frac{PR}{2L} = \text{shearing stress}.$$

(2) may be expressed as a differential equation:

$$\frac{dv}{dr} = \frac{S}{\mu}, \tag{4}$$

where

v = velocity in cm. per sec.,
r = cm. from centre of tube.

It is controversial as to whether or not the fluid having a variable apparent viscosity should be considered as having a true viscosity. Here we shall consider drilling fluids as having true viscosities, and that flow may be described by equation (4). Ambrose and Loomis [3, 1933], measuring the viscosities of bentonite suspensions in a rotation viscometer, found the following relationship between viscosity, rate of shear, and shearing stress:

$$x = mS^n \tag{5}$$
$$= \frac{S}{\mu},$$

where m and n are empirical constants for the fluid in question. From (5),

$$1/\mu = mS^{n-1}. \tag{6}$$

The corresponding equation for flow through a tube is

$$\frac{E}{\pi R^3} = mS^n/(n+3). \tag{7}$$

This equation is equivalent to Poiseuille's Law when $m = 1/\mu$ and $n = 1$.

If capillary tubes of different radii are used in measuring the flow characteristics of a drilling fluid, it is found that the apparent viscosity is not independent of the dimensions of the apparatus. Fig. 4 shows the variation of rate of shear with the shearing stress for a 5% bentonite suspension.

The rate of shear is actually $(n+3)E/\pi R^3$, where n is a constant for the material as determined by experiment. The shearing stress is given in terms of stress per unit length

of the tube. Radii of the several tubes are indicated on the diagram. The curves do not coincide because the fluid was not in the same state of gelation in each case. Fig. 5 shows

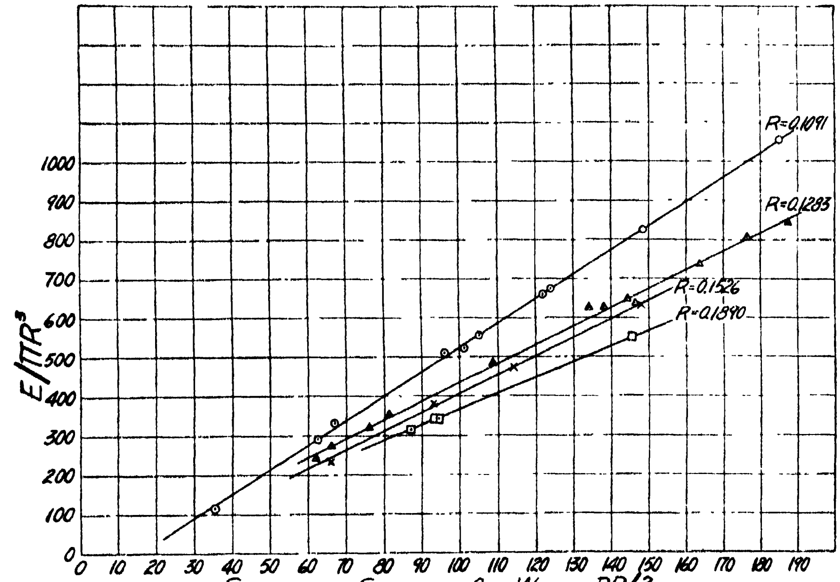

FIG. 4. Flow measurements in capillary tubes. 5% bentonite suspension.

a plot of the log (rate of shear) against log (shearing stress) for a 5% bentonite suspension as measured in a rotary viscometer of special design [3, 1933]. The measurements, made with three combinations of radii of inner and outer cylinders, show no slippage; the method for examining fluids for slippage was suggested by Mooney [32, 1931]. Viscosities determined in this way are independent of the dimensions of the apparatus. Each point was obtained by

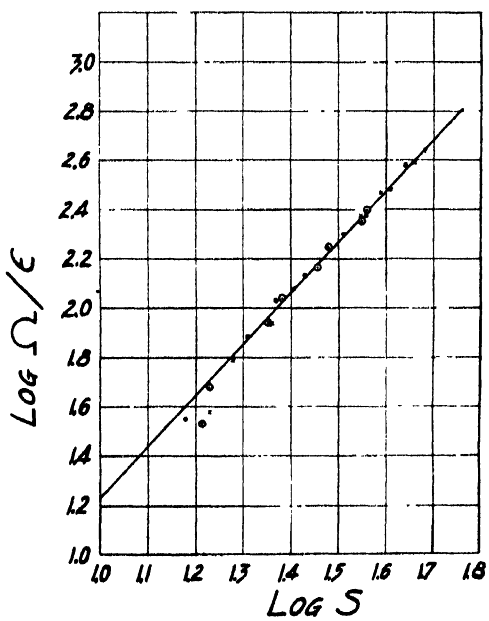

FIG. 5. Rotary consistometer rate of shear plotted against shearing stress. 5% bentonite suspension.

rotating the outer cylinder at a constant rate of shear until the measured shearing stress decreased to a minimum value and equilibrium between the formation and breakdown of the gel had been established. As long as 30 minutes may be required for equilibrium to be attained. It is obvious that such equilibria cannot be established in a capillary viscometer in the few seconds required for an element of fluid to traverse the tube.

It is true that most clays and drilling fluids show thixotropy (the characteristic of having a variable apparent viscosity which decreases as work is done on the material) to a less marked degree than the example. However, the illustration explains some of the difficulties of viscosity measurements in this field of work.

Equation (7) applies only to flow at low rates of shear. The work on bentonite suspensions was extended to measurements of rates of flow in brass pipes, ½ and 1 in. in diameter. Data on some of these measurements are shown in Fig. 6 [3, 1933], where the rate of shear is plotted as a function of the shearing stress on a log-log scale. The region of flow characterized by equation (7) may be defined as non-viscous, and by equation (1) as viscous. In the non-viscous region the slope of the log-log curve is greater than 1·0; in the viscous region, 1·0. In the turbulent region the slope is approximately 0·5.

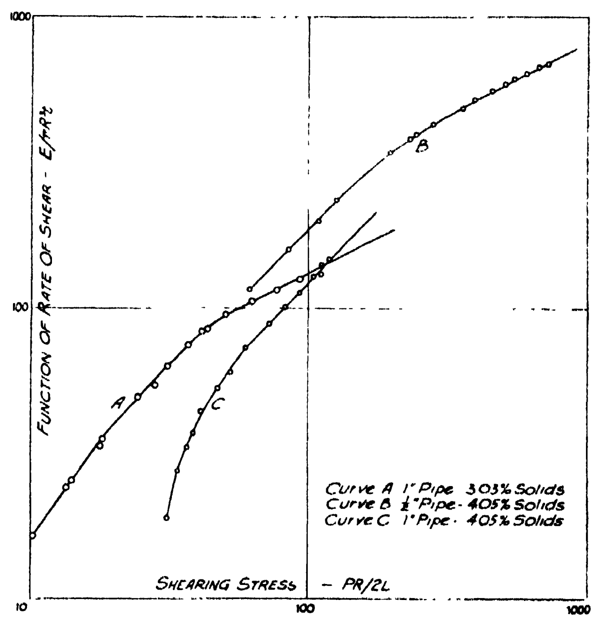

FIG. 6. Possible flow regions for colloidal suspensions.

Curve A shows all three regions for a 3·03% bentonite suspension as measured in a 1-in. pipe. Curve B illustrates the two upper, and curve C the two lower regions of flow for a 4·05% bentonite suspension. The viscosities in the viscous region may be used to calculate the critical velocity at which turbulence begins.

In the measurement of viscosities of such fluids the variation of viscosity with shearing stress (or with rate of shear) is not the only complicating factor. For bentonite suspensions, and to a lesser degree for clays, the viscosity decreases as work is done upon the fluid, until an equilibrium point is reached, where the viscosity becomes a constant at constant rate of shear. This fact accounts for the

conflicting values that may be obtained for the apparent viscosity of a clay fluid in a tube or funnel type of viscometer. It is frequently found that the viscosity of a single sample decreases with every successive passage through the apparatus. A rotary viscometer of the Couette type corrects for this fault. The fluid may be sheared in this apparatus at a constant rate, until the shearing stress reaches a constant minimum value. It has been found that some bentonite suspensions do not reach such a state of equilibrium until they have been sheared at a constant rate for a period of 30 minutes or longer.

The above complications show that viscosity measurements are hardly practical for determining accurate values for use in flow formulae. The critical points between non-viscous and viscous flow and between viscous and turbulent flow are indeterminate for these fluids, except by painstaking and somewhat cumbersome experiments. However, certain measurements of apparent viscosities have a definite value for comparative purposes.

The Stormer viscometer is convenient for measuring comparative apparent viscosities. This instrument does not give absolute values for rotary drilling fluids; baffle-plates, causing local turbulence, prevent the absolute measurement of viscosity. The Stormer is commonly calibrated with liquids of known viscosities, such as oils or glycerine solutions, using several driving weights to furnish a wide range of viscosities. Calibration curves are plotted for variation of the rate of revolution of the inner cup with viscosity for the different driving weights. In measuring the relative viscosities of rotary drilling fluids, the rates of revolution are measured for several weights, and the curve of apparent viscosity for each weight against r.p.s. is interpolated to 10 r.p.s. as shown by Ambrose and Loomis [2, 1931]; at this speed the curves become nearly parallel and asymptotic. Although the values thus measured cannot be applied to actual flow formulae, they are very useful in the comparison of drilling fluids and the effects of chemicals on their properties. The method is merely a measurement of relative viscosities at constant rate of shear. The peculiar minima found by Craft and Exner [13, 1933] in measuring the variation of viscosity with temperature do not appear when measurements are made at constant rate of shear.

A particular difficulty connected with the Stormer viscometer is that it must be calibrated often; wear or dirt in the bearings will cause large discrepancies in measurements.

A convenient and simply constructed viscometer for field use, described by Marsh [28, 1930], consists of a 12-in. funnel 6 in. in diameter at the top and tapering to a 2-in. copper tube drilled to $\frac{3}{16}$ in.; its capacity is 500 cu. cm. The time of efflux for clear water should be 18·5 sec. Viscosities may be reported in seconds, and are a relative measure of the resistance to flow in this particular instrument. The measurements are of use in comparing and checking the consistency of the drilling fluid, but give no absolute measure of viscosity, for the reasons indicated above.

A portable, electrically driven viscometer described by Kerr [22, 1932] has not come into common use.

In summarizing the known information on viscosities of drilling fluids, it may be said that no known method of measurement furnishes values that may safely be used in flow formulae, but methods yielding comparative or apparent viscosities are very convenient for experimental and control work. Fluids of this type have three regions of flow, the non-viscous, viscous, and turbulent regions. The critical points, separating these regions, are indeterminate except by a series of experiments. Various instruments for measuring apparent viscosities give widely varying values.

Several authors have considered drilling fluids as plastic or pseudo-plastic materials. It is commonly known that a 'gelled', quiescent fluid will hold in suspension for an indefinite period, with no apparent settling, particles of greater than colloidal size. Likewise bubbles fail to rise. It appears that the shearing stresses imposed on the fluid by these particles are of insufficient magnitude to cause motion.

The pressure necessary to start flow of a gelled material in a capillary tube may be called the yield value. The authors have attempted to determine yield values, but were unable to obtain consistent results.

Herrick [21, 1932], considering clay suspensions as plastic solids, has attempted to devise a formula for the turbulent flow of drilling fluid through a pipe by incorporating plastometer measurements of viscosity in Williams and Hazen's formula for hydraulic flow. The measurements were made with a single capillary tube, and the results calculated to give the yield value and the 'viscosity'. The derivation of this formula for viscosity is not clear, but its form is similar to that given by Bingham [10, 1922] for the mobility and friction of plastic materials. The mobility (reciprocal of Herrick's viscosity) and the friction factor are assumed to be constants for the material and independent of the radius of the tube, but Bingham's data show regular variation of both with increasing radius. Herrick does not substantiate his equations for the flow of drilling fluids by actual measurements in pipes.

Herrick's modification of the Williams and Hazen formula for a 70 lb. per cu. ft. drilling fluid is as follows:

$$Q = 1{\cdot}24D^{2\cdot63}(P-33{\cdot}3/D)^{0\cdot54},$$

where Q = flow in gal. per min.,
D = inside diameter of pipe in in.,
P = pressure drop per 1,000 ft. in lb. per sq. in.

The factor 1·24 is a modification of the Williams and Hazen experimental coefficient C obtained from Herrick's data; the method of modification is not described. According to Daugherty [14, 1925], the coefficient C has been found to vary between 107 and 170 for water in various types of pipe.

The term $33{\cdot}3/D$ is a correction factor to take into account the yield value of the drilling fluid. The validity of this equation is doubtful, particularly without experimental verification.

The yield value is of some practical significance in determining the maximum sizes of cuttings and gas-bubbles that will be retained without being released. For ready release of cuttings and gas in the slush pits the yield-point should be low, and the fluid should not be in a gelled state. No data are available, however, on the relation between yield-point and retention of gas and cuttings.

Surface Tension.

The small amount of material written about the surface tension of drilling fluid is both meagre and misleading. Surface tension is particularly important in affecting the ease with which bubbles of gas are released when gas-cutting occurs. Consider a bubble of gas in a liquid where

P_g = pressure of gas in the bubble,
P_e = pressure of liquid on bubble,
T = surface tension of liquid,
R = radius of bubble.

The pressure of gas in the bubble is balanced by the sum of the pressure of the liquid and the surface tension:

$$P_g = P_e + \frac{2\pi RT}{\pi R^2},$$

or

$$P_g = \frac{2T}{R} + P_e. \tag{8}$$

If the bubble is considered as containing unit weight of gas:

$$P_g V_g = K \text{ (a constant)},$$

where V_g = volume of gas-bubble,
K = a constant at constant temperature.

Since

$$V_g = \frac{4}{3}\pi R^3,$$

$$P_g = \frac{3K}{4\pi R^3}. \tag{9}$$

Substituting (9) in (8),

$$\frac{3K}{4\pi R^3} = \frac{2T}{R} + P_e.$$

When P_e is unity,

$$\frac{3K}{4\pi R^2} = 2T + R.$$

Neglecting R as small in comparison with T,

$$\frac{3K}{4\pi R^2} = 2T. \tag{10}$$

If T is reduced by the addition of reagents, R is correspondingly increased according to the equation, derived from (10):

$$R_2 = R_1 \frac{T_1}{T_2}, \tag{11}$$

where the subscript $_2$ refers to the property after treatment, and $_1$ before treatment.

In accordance with a modified form of Stokes' Law, the velocity of rise of a bubble in a liquid is proportional to the square of the radius of the bubble. Lowering the surface tension of a mud therefore increases the rate of release for bubbles of gas. This is not true when the reagent acts to stabilize bubbles at the surface by promoting foam, as do some soaps. Non-foaming reagents such as ethyl acetate have been found to reduce gas-cutting when added in relatively small proportions.

III. Chemical and Mechanical Treatment

The general properties of drilling fluids required for specific purposes are outlined above. The usual methods for treating drilling fluids to control their properties may be classed under several headings:

(1) Addition of inert solid materials.
(2) Addition of active solid materials (colloids).
(3) Addition of chemicals.
(4) Mechanical treatment.

Admixtures.

The commonest drilling fluid is composed of clay and water. In fields where clays are not available, colloidal material must be used to take the place of the clay. Bentonitic materials are generally used for the purpose.

Inert materials such as ground silica (Commercial Opalite is an example) are added to the base drilling fluid to give it weight, that is, to increase its density, and to assist in building a wall or filter-cake during drilling.

The effect of a bentonite in stabilizing an inert material is shown in Fig. 7 [2, 1931]. The pure Opalite suspension settled to the extent of 40% in 24 hours, but the addition of 3 parts of bentonite per 100 parts of water reduced

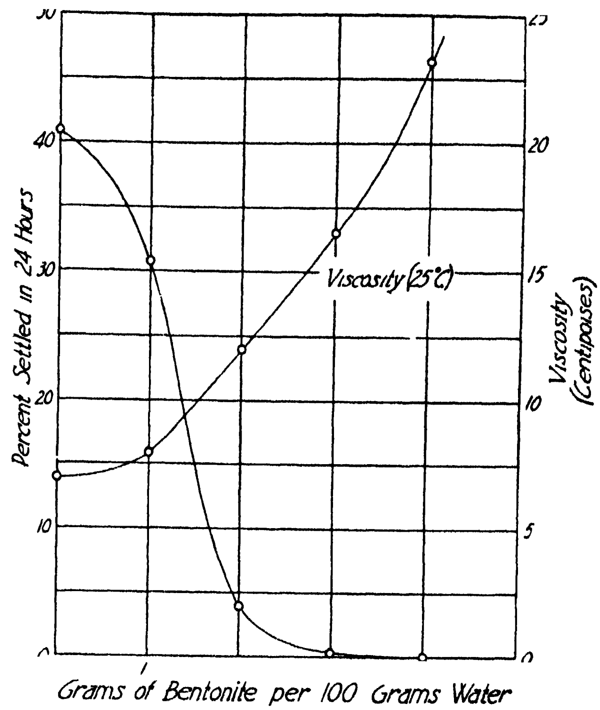

FIG. 7. Amorphous silica suspensions. Density, 1·44.

settling to a negligible value. The reduction in settling is greater than can be accounted for by the increase in apparent viscosity. The finely divided silica settled very slowly because of its plastic properties imparted by the bentonite. Shearing stresses exerted on the fluid by the particles were not sufficient to break the gel. Commercial barytes, sold under the name of Baroid for drilling purposes, may be obtained in several grades containing different proportions of bentonite. The fraction of bentonite is less in grades used for heavy, dense, drilling fluids. Iron oxide may be stabilized in a similar manner.

A wide variety of chemicals have been proposed for treating drilling fluids to improve their characteristics. These are usually neutral or alkaline in nature, rather than acid, for several reasons. Clays contain a small amount of carbonates that will neutralize the acid, thereby destroying its effect; strata encountered in drilling are also commonly cemented with carbonates. In addition acidic drilling fluids would be corrosive to equipment. Ambrose and Loomis [4, 1933] have shown that drilling fluids are more readily stabilized in an alkaline than an acid condition, and maximum stability is encountered at a pH of about 11·0, that is, in alkaline solution. Stability, as measured by the rate of settling of the solids, may be greatly increased by the addition of the proper alkaline chemicals. These include caustic soda, sodium silicate, and various mixtures of alkali with weak organic acids such as tannic and humic acids. The number that may be used is large. The ratio of alkali to acid has a great effect on the properties of such mixtures, excess alkali usually improving the action. Small quantities of chemicals may lower the viscosity as well as increasing the stability, while further addition of chemical increases the rate of settling with further reduction of viscosity. The effect of several of these chemicals on the viscosities and

settling properties of typical clay drilling fluids is shown in Figs. 1 and 2.

Mineral salts such as sodium and calcium chlorides have a flocculating effect on clays; a more detailed account of the action of salts is given by Doherty, Gill, and Parsons [16, 1931]. Oilfield brines are often used as make-up water in spite of their tendency to accelerate settling of colloids. Salt has been added to drilling fluids to give them weight, but this is not considered good practice, particularly because of the corrosive effect on drilling equipment. If the use of salt-water is unavoidable, alkali may be used for increasing stability.

The principal use of salt in treating drilling fluids has been in an attempt to prevent heaves in shale formations.

Various admixtures have been used in sealing cavernous and porous formations where returns are lost. Examples are sawdust, cotton-seed hulls, wire line, scrap iron, cement, and bentonite [35, 1931]. Dry beans, peas, cotton-seed hulls, or any materials which swell with water are available. Concentrated bentonitic mixtures have the advantage that they gel rapidly to form a semi-solid, as soon as motion ceases. Because of their extremely high viscosities at low rates of flow, these mixtures offer considerable resistance, finally bridging as they flow into crevices and caverns.

Mechanical Treatment of Muds.

Various mechanical methods have been employed for conditioning rotary drilling fluids, particularly for removing cuttings and gas bubbles retained in suspension.

Benjamin [6, 1930] describes an elaborate treating plant operated at Ventura, California, and centrally located to serve a number of wells. As much as 15,000 bbl. of drilling fluid per day were treated by an installation including 4 Dorr bowl classifiers and a Dorr Traction Thickener, 200 ft. in diameter. The method was based on differential settling and separation of sand, gas, and oil from the clay, after dilution with water.

A centrifugal separator [38, 1930] has also been used for a similar purpose. More widespread is the use of vibrating screens in separating cuttings and gas. A number of home-made mechanical separators, too numerous for specific mention, have shown varying degrees of efficiency for the same purpose.

Because of low cost and relatively high efficiency, chemical treatment of drilling fluids has become widespread, while mechanical methods are limited to the occasional

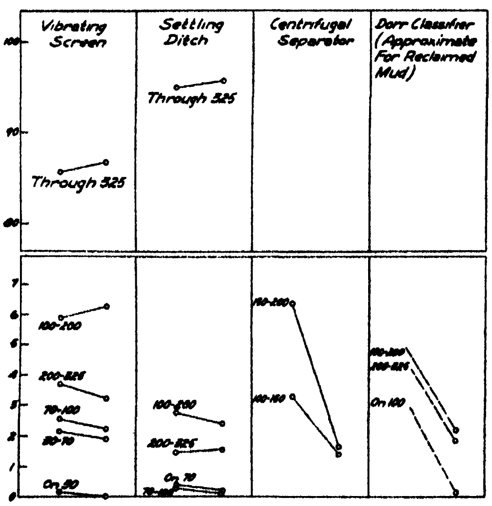

FIG. 8. Efficiencies of mechanical methods of treatment.

use of vibrating screens. Fig. 8 [26, 1932] with data from several published sources indicates the comparative efficiency of mechanical methods of treatment. From left to right the points indicate compositions before and after mechanical treatment. By comparing the data with Fig. 2, the enormously greater efficiency of chemical treatment will be evident.

IV. Mineralogical Constituents

Minerals are used for drilling fluids for three main and distinct purposes, wall-building, weighting, and stabilization.

Clay, the most common mineral constituent of drilling mud, varies considerably in properties, but little in specific gravity, which is usually in the neighbourhood of 2·5. The average clay contains high percentages of silicon and aluminium compounds with minor quantities of iron, calcium, magnesium, sodium, and potassium. The following is the analysis of the solid content of drilling fluid used in drilling a well in Venezuela:

Constituent	*Percentage*
SiO_2	57·17
Al_2O_3	20·01
Fe_2O_3	9·44
CaO	0·92
MgO	0·81
BaO	0·00
CO_3	1·49
Loss on ignition	9·36
Total	99·20

This analysis tells us little with respect to the properties required in drilling. There has been no correlation between chemical analyses of clays and their suitability for drilling purposes. The more important data regarding this same drilling fluid are:

Weight	9·17 lb. per gallon
pH	8·9
Density of solids	2·78
Percentage passing a 200-mesh screen	98·5
Percentage settled in 24 hours	0·24
Apparent viscosity at 77° F. (600 r.p.m. Stormer viscometer)	10·4

The above simple and rapid test furnishes good comparative data, none of which is particularly concerned with the chemical analysis.

The *pH* indicates that the fluid is alkaline, tending to inhibit corrosion. The sand content is small, as indicated by sieve analysis, the settling rate is satisfactory, and the viscosity is low. For general drilling purposes the sample shows satisfactory properties. Similar tests provide a simple and rapid method for evaluating clay samples. It is important that the sand content should be low, to prevent scoring of pumps, and that the viscosity should be low enough to allow release of cuttings and gas.

The colloidal character of an admixture determines the percentage that may be added to water to make a usable drilling fluid. If the limiting maximum relative viscosity is taken as 30 centipoises (Stormer viscometer, 600 r.p.m.), representative limiting concentrations of solids and specific gravities of various drilling muds are as shown in the following table:

Limiting Concentrations of Admixtures

Admixture	*Percentage solids*	*Pounds per gallon*
Aquagel	3·7	8·5
Wyoming bentonite	8·7	8·8
Baroid (1931)	47·0	13·0
Pierce Junction (Texas) clay	23·0	9·7
Haematite	38·0	11·6

The properties of clays vary sufficiently to allow the use of higher percentages of clay than that shown. Chemicals that lower the viscosities of clay muds allow the clay content to be increased slightly, but not to a remarkable extent. Heavier Baroid drilling fluids may be made from barytes by reducing the percentage of bentonite used for stabilization.

Bentonites.

Bentonite is thought to be a volcanic ash, partially altered by leaching. Samples from various localities vary in composition, and contain approximately 45 to 70% silicon as SiO_2, 15 to 25% aluminium as Al_2O_3, water, and minor amounts of other combined metals [7]. Bentonite may be considered as a mixture of compounds of the form:

$$Al_2O_3 \cdot xSiO_2 \cdot yH_2O,$$

with impurities, and are probably hydrated silicates of aluminium. Clays appear to be of similar chemical composition.

Some bentonites probably owe their remarkable activity to the fact that they contain as much as 50% of particles having colloidal thickness, and to the presence of salts that aid in their water adsorption and peptization. As has been intimated, bentonitic dispersions are thixotropic, or reversibly gelatinous. This gel formation is probably largely responsible for the protecting or stabilizing action exerted on inert particles by bentonite.

Of a number of bentonitic mud stabilizers on the market in the United States, the more reactive with water are those that have been chemically treated for use in drilling mud, such as Aquagel. Commercial bentonites may be treated with chemicals such as magnesium carbonate to give such properties. The addition of slaked lime will increase the viscosity of bentonite-water mixtures, but has a coagulating action. In drilling through bentonitic strata, salt-water may be used to prevent excessive sloughing and swelling of the mineral.

Weighting Materials.

Practically any inert mineral may be stabilized or held in water suspension with the aid of clay or bentonite. Admixtures are used particularly where heavy clay drilling fluids are too viscous for releasing cuttings and gas, where a clay drilling fluid of suitable viscosity does not have sufficient weight, or where the proper clays are not available. Weighting materials are substitutes for clays, in that they are somewhat inert, or may be added without unduly increasing viscosity. Since the viscosity increase due to addition of inert material is mainly dependent upon its volume, the heavier or more dense the mineral, the lower will be the increase in viscosity per unit weight of addition.

Stroud's [39, 1922] early investigation of admixtures suitable for compounding drilling fluids to restrain gas in high-pressure wells led to the common use of barytes. Less common minerals such as finely ground silica and iron oxide are also used. The common minerals used for increasing weight include the following:

Common Drilling Fluid Heaviers

Mineral	*Density*	*Chemical formula*
Barytes	4·2–4·5	$BaSO_4$
Haematite	4·9–5·3	$Fe_2O_3 \cdot xH_2O$
Amorphous silica	2·6	SiO_2
Clay	1·8–2·6	

The utility of any mineral is necessarily determined by the supply, cost of grinding to specifications, and density. Ground limestone or calcium carbonate, having a density of about 2·7, has recently been suggested, particularly for drilling wells that are to be acidized. It can be produced at a reasonable cost and can be stabilized.

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THE MINERALOGICAL CONSTITUTION OF CLAYS

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THE study of clay minerals is one of considerable difficulty, and it is only within recent years that methods of investigation have become available which are likely to give more reliable results than have been obtained in the past. Nevertheless, for a number of years there have been publications concerning the minerals present in clays, but many of them, more particularly those about the finest material, now require checking and confirming by X-ray examination, in addition to optical, chemical, and dehydration tests. The general results of recent research are the definition of a comparatively few clay mineral species, and the explanation of many hitherto considered species on the basis of isomorphism, adsorption, or solid solutions.

Clays, in general, are polydisperse systems and may have particles ranging in diameter from sand grains of 1 mm. down to particles of 10 $\mu\mu$ or less. According to Odén [14, 1921–2] the bulk should be about 2 μ in diameter. Mechanical analyses may show an almost complete absence of certain sizes of particles, but this is not common and not necessarily an original condition. Clay minerals have an eminent basal cleavage and are fragile. Thus the crystals may become subdivided in mechanical analysis and give an erroneous idea of their size in the original clay. For clays used in aqueous suspension, the size distribution as shown by sedimentation analysis may be of more importance than the size of the original crystals.

The Coarse Fraction

Some geologists make the following divisions of sediments according to grain sizes (Boswell [2, 1915]):

Sand: 1 mm. maximum to 0·1 mm. minimum diameter.
Silt: 0·1 „ „ 0·01 „ „
Mud or clay: 0·01 mm. maximum and less.

It is suggested that a typical clay should contain not less than 50% of the mud or clay grade. The mechanical analyses of a few clays are shown in Fig. 1. A number of workers have made petrological examinations of the coarser fractions of clays (mainly the silt and sand content), and the following are some of the more common minerals observed, both as regards frequency of occurrence and amount: anatase, garnet, glauconite, gypsum, ilmenite, kyanite, leucoxene, limonite, magnetite, marcasite, muscovite, plagioclase, quartz, rutile, staurolite, tourmaline, and zircon. Many other minerals have been recorded less commonly, and include the following: actinolite, andalusite, apatite, aragonite, arfvedsonite, augite, barytes, biotite, brookite, calcite, cassiterite, chlorite, chloritoid, corundum, dolomite, enstatite, epidote, glaucophane, haematite, hornblende, hypersthene, microcline, monazite, orthoclase, phlogopite, pyrolusite, siderite, sillimanite, sphene, spinel, titanite, topaz, and zoisite.

The Fine Fraction

Amongst soil physicists it is customary to regard all particles of equivalent diameter less than 2 μ, as given by standard methods of mechanical analysis, as the true clay fraction, and Joseph [7, 1927] has suggested that this should also be taken as the colloid content (Zsigmondy gives 200 $\mu\mu$ as the upper limit of the colloidal range, and Freundlich gives 1 μ). There is little doubt that the characteristic and useful properties of many clays are dependent on the finer particles present, and perhaps more on their physical condition than their chemical constitution. On account of their laminar nature, many particles will be included in the true clay fraction which will have maximum dimensions considerably in excess of 2 μ. According to Bole [1, 1922], there may be 10–40% of colloidal dimensions in a clay, and this is mainly crystalline. If the clay is not in its maximum state of dispersion, there will appear to be fewer of the particles of the smaller sizes, and a low true clay content will be inferred from the mechanical analysis. By means of the centrifuge it is possible to study the size distribution of clay particles less than 2 μ in equivalent diameter, and Marshall [9, 1930–1] has shown that a bentonite, which is usually regarded as the most colloidal of all clays, had 49% of this fraction greater than 200 $\mu\mu$ equivalent diameter, whilst a kaolin had 94%.

The crystalline clay minerals, despite their fineness of grain, are characterized by a platy structure and an excellent basal cleavage, and they possess many of the physical properties of the mica division. Their crystallinity is occasionally observable under low-power magnification, but the crystallinity of the finest particles has only been demonstrated by their X-ray diffraction patterns. Quite a number of minerals have been recorded as occurring in the true clay fraction, or at least in the finer fraction, but considerable doubt exists as to the validity of some of the identifications. As major constituents, the following have been noted:

Kaolinite, $Al_2O_3 \cdot 2SiO_2 \cdot 2H_2O$. Investigation has shown that the kaolin minerals are, on the whole, not important in clays. McDowell [12, 1926], Galpin [5, 1912], and others report kaolinite in clays, frequently as the dominant mineral and occurring as fanned or vermicular aggregates with ribs of hydromicas. There seem to be all stages from sericite to kaolinite. It is distinguished from the other kaolin minerals, nacrite and dickite, by X-ray, optical, and dehydration data, and the fact that it adsorbs dyes strongly, becoming pleochroic. The kaolin minerals differ from other clay minerals in their low birefringence, and of the three, kaolinite (Ross and Kerr [16, 1931]) is the only one likely to occur in sediments, though Ross [15, 1927] has stated that it never seems to be present in soils and shales, and, indeed, is rare in nature. Again, some doubt exists concerning its origin. Ross [15, 1927] attributed it to hydrothermal solutions, whilst Ross and Kerr [16, 1931] thought that it results from the profound weathering of aluminous rocks, from the leaching action of humic acids under swamps, and from the action of sulphuric and carbonic acid-bearing waters on aluminous rocks. More extensive leaching, with removal of silica, leads to its being mixed with bauxite and diaspore. The uncertainty about its occurrence may be due partly to the fact that anauxite and possibly leverrierite are commonly mistaken for kaolinite (Ross [15, 1927]).

Anauxite, $Al_2O_3 \cdot 3SiO_2 \cdot 2H_2O$, **is similar to kaolinite in**

many respects, e.g. X-ray and optical properties (Tomkeieff [19, 1933]), and it may prove to be merely kaolinite with adsorbed silica, or an intermediate product between kaolinite and pyrophyllite. It is thought to arise from augite, biotite, and chlorite in sediments, and to be the result of profound weathering, although some may be formed by hydrothermal solutions. Anauxite is widespread, but seldom a dominant clay mineral, and is found in brackish-water, deltaic, and marine sediments. Along with halloysite it is said to form the bulk of what is usually termed kaolinite (Ross [15, 1927]).

Micaceous halloysite is quoted as containing RO or R_2O_3 groups.

Pyrophyllite, $Al_2O_3 \cdot 4SiO_2 \cdot H_2O$, seems to be widely distributed in nature.

Gibbsite, $Al(OH)_3$, has been noted in a number of clays.

The bauxite group of minerals may be mixtures of kaolinite and gibbsite, e.g. allophane (classed by some investigators with the kaolin minerals) would contain one molecule of each. Pure bauxitic minerals are rare, for there are usually admixed clay minerals and iron oxides. There is no evidence, statistical or otherwise, for the existence of

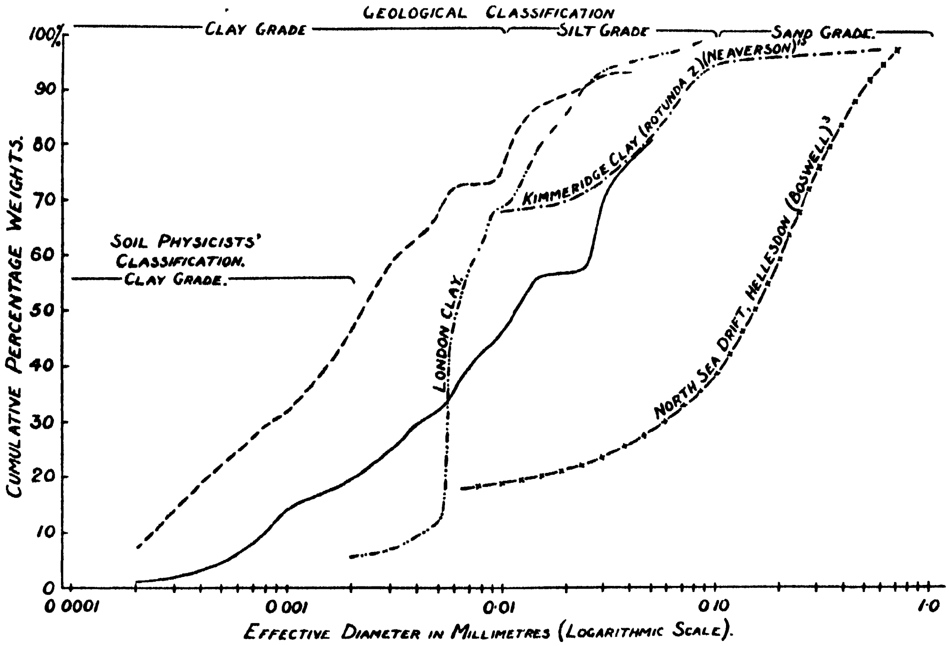

FIG. 1.

bauxite ($Al_2O_3 \cdot 2H_2O$) as a mineral species (Tomkeieff [19, 1933], Wherry [20, 1925]). Therefore Hendricks and Fry's [6, 1930] report of two soil colloids giving bauxite-type diffraction patterns needs reconsideration.

Laterites are ferruginous bauxites, being merely mechanical mixtures of alumina and ferric monohydrates with alumina trihydrate and ferric oxide.

Halloysite, $Al_2O_3 \cdot 2SiO_2 \cdot nH_2O$, has been shown by X-ray work to be submicroscopically crystalline kaolinite (Ross and Kerr [17, 1934–5]). It has a higher water content than kaolinite and tends to have more alumina. This, considered with the fact that its diffraction pattern is not so sharp, has led to the suggestion that it may contain adsorbed non-crystalline matter. It is the dominant mineral of so-called kaolin (Ross [15, 1927]), and fresh-water clays are composed mainly of halloysite. Halloysite is frequently associated with diaspore and gibbsite, and Hendricks and Fry [6, 1930] found the diffraction patterns of a number of soil colloids, especially those with high iron content, to resemble the halloysite pattern.

Allophane gives an indistinct X-ray diffraction pattern, and seems to be the only truly amorphous mineral of the kaolin group. Dehydration curves indicate that the water is mainly adsorbed, and it may prove to be merely a mutual solution of silica, alumina, and water, with minor bases and acid radicals (Ross and Kerr [17, 1934–5]).

Leverrierite may be $2Al_2O_3 \cdot 5SiO_2 \cdot 5H_2O$, but according to Tomkeieff [19, 1933] the silica-alumina ratio ranges 2·3–3·7, and the water-alumina ratio 1·3–4·5. There is also some lime or magnesia. It occurs as hexagonal flakes similar to kaolinite, but a redefinition of the species has called for the checking of all past observations of its occurrence. Some mineralogists have discarded the name, and micaceous halloysite occupies its place as a member of the bentonitic clay minerals. It is not impossible that it may yet prove to be merely anauxite (Tomkeieff [19, 1933]).

Montmorillonite, often given as $(Mg \cdot Ca \cdot)O \cdot Al_2O_3 \cdot 5SiO_2 \cdot nH_2O$, is the clay mineral of most bentonites. It appears to be completely isomorphous with other members of the bentonitic group, and its optics are the same as those of low iron beidellite. The X-ray diffraction patterns of these two are so far indistinguishable (Ross and Kerr [16, 1931]), and at present chemical analysis is the best distinction. Much of the water of montmorillonite seems to be adsorbed and not constitutional, and some of it may be displaced by potash. Montmorillonite results from the decay of volcanic glasses, and is found in marine shales and in the soils of cool, moist regions. It has been shown to be identical with smectite, an important constituent of fuller's earth (Kerr [8, 1932]).

Recent work shows that the fundamental montmorillonite unit has a four-to-one ratio of SiO_2 to Al_2O_3, and a definite number of essential hydroxyl groups in addition to others less closely held. Mixtures, adsorption, and base-exchange may explain the alkali and alkaline-earth metals often recorded in montmorillonite and in other clay mineral analyses.

Beidellite, $Al_2O_3 \cdot 3SiO_2 \cdot nH_2O$, occurs in some bentonites and in many clays and shales. Indeed, it seems to be

the dominant soil- and clay-forming mineral. It usually contains iron, and there can be all stages between pure beidellite and its iron equivalent, nontronite

$$(Fe_2O_3 \cdot 3SiO_2 \cdot nH_2O).$$

In shales it resembles sericitic mica. It is formed from volcanic glasses, from ferromagnesian minerals, and, at times, from felspars. Arid regions, where leaching is not profound, have a beidellite-like mineral.

Saponite, $9MgO \cdot Al_2O_3 \cdot 9SiO_2 \cdot nH_2O$, is probably an essential constituent of some bentonites. Ross and Kerr [16, 1931] place saponite in the montmorillonite-beidellite group, but Tomkeieff [19, 1933] classes it with the chlorites, or, when the magnesia content is lower, as a link between the chlorites and his fuller's earth group (which includes the bentonites).

The bentonite group is related not only to the pure clay minerals, but also to the mica group. The alkali content diminishes, as does the relative amount of RO, whilst the water content increases in going from the micas to the bentonitic minerals. In addition, the water of the bentonitic group is largely adsorbed, as distinct from the kaolin group where it seems to be mainly constitutional. The birefringence of this group is less than that of the micas, but higher than the kaolins.

The potash-bearing clays probably form a small proportion of many soils and shales, the only extensive beds being the Ordovician meta-bentonites. They resemble sericite, and potash seems to be an essential constituent. It is interesting to note that Hendricks and Fry [6, 1930] found that a mixture of 15% of quartz with montmorillonite gave a diffraction pattern very much like that of the Ordovician bentonite.

The hydromicas are a little studied group, lying between the micas and the bentonitic group (Tomkeieff [19, 1933]), and may embrace the potash-bearing clays. Boswell [4, 1933] gives two members of this group as: potash bentonite $K_2O \cdot Al_2O_3 \cdot 5SiO_2 \cdot 3 \pm H_2O \cdot$; potash gouge clay,

$$K_2O \cdot Al_2O_3 \cdot 2-4SiO_2 \cdot 3 \pm H_2O.$$

Their birefringence is higher than kaolinite, but lower than sericite or muscovite. They may represent a stage in the decay of sericite, potash having been lost and water gained. The hydromicas form the bulk of some clays and occur frequently.

Sericite is reported by McDowell [12, 1926] to be a common constituent of clays.

Bravaisite. From an extensive study of clays, Thiébaut concluded that varieties of bravaisite, i.e. a complex aluminium silicate with essential ferrous, magnesia, and potash bases, were frequent constituents of clays.

> 'It seems probable that a number of clay minerals exist which have not yet been properly characterised' (Marshall [10, 1935]).

Quartz is one of the major accessory minerals of clays, and Somers [18, 1919] states that the very fine grains may sometimes be confused with kaolinite. McDowell [12, 1926] records diaspore, $Al_2O_3 \cdot H_2O$, as a major accessory clay mineral.

A considerable number of minor accessory minerals have been observed: pyrite, siderite, limonite, biotite, muscovite, felspar, hornblende, magnetite, rutile, zircon, titanite, calcite, gypsum, garnet, and corundum.

A few attempts have been made to classify the clay minerals, usually on the basis of the silica-alumina ratio and the base exchange properties, which, according to Joseph [7, 1927] and Mattson [11, 1929], run parallel, along with a number of other properties of clays, such as adsorption, heat of wetting, and degree of swelling. Marshall [9, 1930–1] groups the potash-bearing clays with montmorillonite, since they show true and not merely superficial base exchange.

As research proceeds it is probable that some of the identifications of the fine constituents listed above will be discarded or found to overlap, and the number of important true species amongst the clay minerals may prove to be very small. The present X-ray technique does not permit the recognition of constituents forming less than about 10% of the sample, and materials with insufficient crystallinity to show reaction are not identifiable. Hence there is much scope for the devising of methods of separation or of other lines of attack whereby these two classes of substances may be identified.

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OIL-WELL CEMENTING

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Introduction

NEXT to the actual finding of oil or gas in a well, the proper exclusion of water from the productive formations is possibly the most important feature of the business of producing oil.

Many thousands of wells have been successfully and permanently protected from water by the proper use of Portland cement, which is a very low-priced commodity available in generally uniform quality to practically every drilling well. This availability and low price is due to the large volume of cement manufactured and distributed for so many purposes other than oil-well cementing, such as building construction, road construction, dams, &c.

The great depths to which wells are now being drilled, and the large number of wells that are being cased with single strings of pipe, are factors which are rapidly increasing the collapsing strains on the casing. It is essential, therefore, that cement should be placed behind the casing, not only for the exclusion of water from the productive formations, but also to protect the casing from the tremendous collapsing pressure to which it may be subjected.

A properly cemented well assures the following important factors of safety:

1. Provides a permanent seal behind the casing regardless of the type of formation.
2. Affords permanent protection to the producing formation from upper water.
3. Protects casing, where cemented, against collapse due to external pressures.
4. Prevents corrosion, the cement keeping highly mineralized fluids from the casing.
5. Prevents shifting formations, the cement forming a tight seal in the space between the hole and the casing.
6. Prevents migration of fluids from one stratum to another.
7. Protects casing when shooting.
8. Prevents blow-outs from high-pressure gas behind the casing.
9. Conserves oil or gas in shallow productive sands behind the casing.
10. Allows casing to be set any distance from bottom, instead of the old practice of making a seat.
11. Affords protection of the production strings when the larger strings of casing are pulled in cable-tool wells.
12. Provides protection to shallow fresh-water sands used for domestic water-supply; also to shallow coal formations.

During the steady and continuous development of mechanical cementing equipment to achieve all the above purposes and to keep pace with continued deeper drilling, it was also necessary to develop the equipment to meet such incidental problems as:

1. Breaking circulation around the casing by means of pump-pressure applied to the circulating fluid.
2. Killing blow-outs by means of pump-pressure applied to fluid.
3. Accurate measuring of lineal depths in wells.
4. Detecting source of leaks due to split casing.
5. Cementing-off leaks.
6. Plugging-back with cement to shut off either bottom-hole water or intermediate water or to abandon wells.
7. Plugging-back with cement for side-tracking purposes.
8. Plugging-off crevices, cavities, and 'thirsty formations' that cause lost circulation.
9. Mixing drilling fluid materials.
10. Treating drilling fluids, &c.

Oil-well cementing is a practice of placing cement slurry, consisting of a mixture of Portland cement or certain rapid-hardening cements and fresh water, in wells which are being drilled for oil, gas, salt, or sulphur, the slurry being placed either behind a string of casing or in the open hole below the casing. When the cement slurry is placed behind a string of casing, its primary function, after it hardens, is to form a permanent seal to prevent water in upper strata behind the casing from travelling downwards around the casing into the well. When the cement slurry is placed in a portion of the open hole below the casing, it is usually for the purpose of shutting-off water coming from the bottom of the well or from some intermediate stratum.

Methods are available for placing cement slurry properly either in wells being drilled by cable tools, with or without circulating fluid in the hole, or in wells being drilled with rotary tools where drilling fluid completely fills the well and circulation of the drilling fluid is a regular procedure. In these methods the basic procedure is to mix the dry cement with fresh water at the proper water-cement ratio, which makes a fluid called 'cement slurry', which can be picked up by the circulating pumps and pumped into the casing or tubing in a well and downwards through the tubing or casing to its intended place in a well.

Cementing Equipment

The mechanical equipment used in oil-well cementing practice may be classified as surface equipment and sub-surface equipment. Surface equipment is designed to move over the most difficult roads from well to well under its own power, and on short notice to mix and pump continuously and thoroughly various amounts of cement slurry at a wide range of mixing speeds and pumping pressures, instantly selective, according to requirements in a well. The same surface equipment used for placing cement slurry behind casing in wells is also used for plugging-back operations in which the cement slurry is placed in a portion of the hole below the casing for such purposes as shutting off bottom-hole water or intermediate water, or for side-tracking lost material in the bottom of a well or for side-tracking to straighten crooked holes.

The mechanical cementing equipment which operates at the surface combines, essentially, transportation, pumping, mixing, and measuring. The pumping system includes pumps, water tank, suction box, manifold and circulating connexions between the cementing pumps and the top of the casing.

Surface-cementing equipment may be classified as either

steam or gasoline motor driven. The former depends upon steam being available at a well to supply power for the pumps. The motor-driven type operates independently, receiving power for the cementing pump through a take-off from the truck motor, and receiving power for the mixing pump from an auxiliary gasoline motor. Gasoline-motor driven equipment was developed primarily for use at electric, gasoline, or Diesel powered drilling rigs or at cable-tool rigs where sufficient steam is not available for steam-driven equipment. (Figs. 1 and 2).

Although motor-driven equipment has a number of advantages, under certain conditions, over the steam type, yet modern steam equipment has the advantage of being less complicated, more flexible, and can handle more volume at almost as high pressures. Until the introduction of the latest steam equipment, the motor-driven type had been much more capable of performing under extremely high pressures.

As modern cementing equipment is capable of pumping at higher pressures, but often at less volume, than the regular circulating equipment at drilling wells, the surface hook-up should be such that immediately after the cement slurry is pumped into the casing by the cementing pumps the circulating fluid can be pumped in by the regular slush pumps until the measuring line indicates that the cement slurry is properly placed or until the regular pumps are no longer able to furnish sufficient pressure. In this case the high-pressure cementing pumps, having been flushed clean while the regular circulating pumps are being used, can be immediately applied. When cementing casing in very deep wells where high pumping-pressures may be necessary, a steel standpipe may be placed on the derrick floor to provide instant changing from one pumping system to another. At the bottom of the standpipe is a two-way connexion, with valves, one going to the regular circulating pumps and the other, through high-pressure tubing, to the cementing pumps. This simple arrangement affords several advantages. To change from one pumping system to the other merely requires opening one valve and closing another. A flexible jointed steel cementing hose, swinging from the top of the standpipe to the plug container on top of the casing, allows the casing to be moved, if necessary, during the cementing operation.

The use of a quick-change cementing head or a plug container are devices which are used to facilitate the placing of cementing plugs in the casing when cementing a very long string of casing.

A plug container is a device which consists essentially of a chamber into which a cementing plug or plugs may be placed, a means for holding and quickly releasing the cementing plug in the chamber, and a manifold which allows the cement slurry to be pumped into the casing below the cementing plug and then allows the circulating fluid to be pumped into the plug container on top of the cementing plug which has been released from the container. The measuring line and stuffing-box are installed on top of the plug container so that the measuring line can be started after the plug, as soon as this is released, for the purpose of measuring the downward travel of the plug and the cement slurry just below it. The primary purpose of the plug container is to speed up the cementing operation in very deep wells by eliminating the time that formerly was needed for removing and replacing a swaged nipple in order to put the top cementing plug into the casing.

In addition to the plug container there are several types of quick-change cementing heads designed for the purpose of shortening the time required to place cementing plugs in the casing.

The measuring device is an important piece of cementing equipment showing instantly and continuously at the surface the downward travel of the cement slurry, thereby indicating the influences of subsurface factors.

Subsurface Equipment and Physical Factors

The larger the inside diameter of the casing and the longer the string of casing the greater will be the amount of cement slurry and circulating fluid required to be pumped into the casing; and unless the speed of pumping these fluids into the well can be increased proportionately the greater will be the time required for the cementing operation. Since the time required for pumping this volume of fluid into the casing has a very important relation to the setting of the cement slurry, the cementing and circulating equipment must be so arranged, both as to volume and pressure capacities, that the time required to place the slurry behind the casing is less than the time required by the cement to set sufficiently so that it is no longer movable.

The temperature conditions in a well must also be considered. High temperature accelerates the setting action of cement slurry. The higher the temperature of the circulating fluid the shorter will be the setting time of the slurry. Temperature of the circulating fluid increases, due to contact with the warm formations in the well. The casing becomes heated, due to contact with the warm circulating fluid. The cement slurry is influenced by contact with the warm casing during its travel downwards through the casing and by contact with the warm formations during its upward travel behind the casing.

There have been deep wells in which working temperatures, which affect the cement slurry, have been lowered considerably by the use of ice for cooling a batch of mud to be pumped into the casing just ahead of the cement slurry or to chill the water with which the cement is mixed. Just as high temperature accelerates the setting time of the cement slurry, low temperature retards the setting time. The chilling of the mixing water provided an additional safety factor of time for placing cement in deep wells. A chemical retarding agent for delaying the setting time of cement under high temperatures has also been developed.

The greater the obstruction or restriction in floating and guiding equipment installed in the casing the greater the hindrance to flow of cement slurry. It is essential that floating equipment should have not only the greatest total amount of clearance consistent with sufficient floating strength, and be of a material that can be readily drilled out, but the minimum opening or restriction in the float valve must also be as large as possible.

It is the usual practice to place the float valve in the casing at least one joint from the casing shoe when one float is used, and at the first and second joints from the bottom when two floats are used.

The cross-sectional area of the annular space behind the casing and couplings in a well not only has an important relation to the successful placing of cement in deep wells, but before the cementing operation begins and after the casing is run it is an important factor in breaking circulation. The smaller the area of annular space the greater will be the friction on the circulating fluid and the greater will be the pump-pressure required.

The gelation and viscosity of the circulating fluid in the restricted annular space behind the casing may be so great that some porous formation which, although already sealed

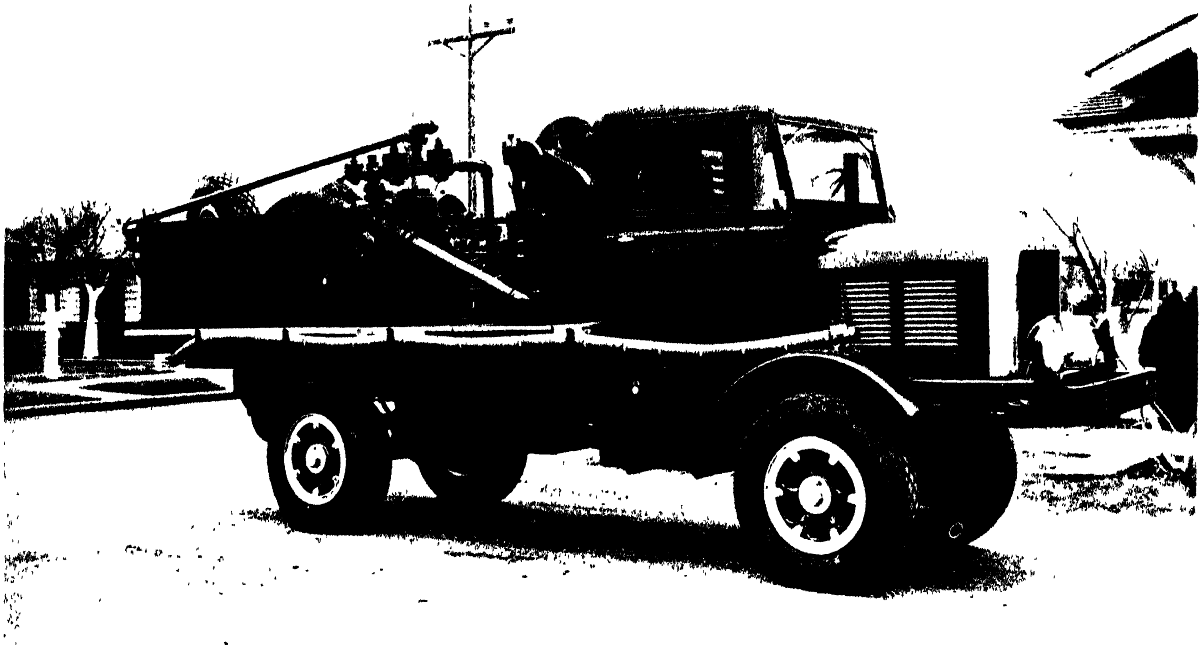

FIG. 1 Latest type of gasoline motor-driven cementing equipment in which the truck motor drives one of the cementing pumps and an auxiliary motor drives the other This type of equipment is designed for cementing jobs at which steam is not available

FIG. 2. Latest type of steam cementing equipment with three high-pressure pumps

against entry of fluid under normal pressures while drilling, might, under the pump-pressure required to overcome gelation and friction in the annular space, start taking the circulating fluid and prevent circulation returns at the surface. When such difficulties seem likely, avoidance lies in the careful selection of a casing programme which provides maximum annular space; in using chemical or physical control of the circulating fluid to provide lower yield-point and/or viscosity; and to prevent excessive building up of a sheath of solid particles on the wall of the hole while drilling, causing 'tight hole' conditions such as are found in areas where natural drilling muds in deep wells are highly colloidal and viscous.

It is very difficult to conceive open hole as being perfectly smooth, and along which the casing has continuous contact for any considerable distance. The couplings on the casing and irregularities in the wall of the hole prevent this. However, on the assumption that casing might have contacted with the hole for a short distance at some critical point, which might prevent cement from thoroughly surrounding the casing at that point, the use of a suitable casing centralizer would remove the doubt.

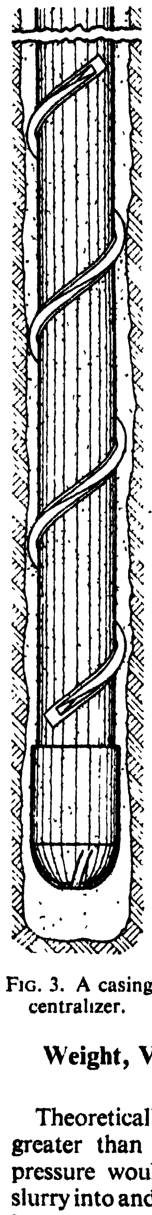

FIG. 3. A casing centralizer.

There is a casing centralizer and cement guide in use, made of a flexible rubber strip, triangular in cross-section, which is attached to a flat metal base, and preformed as a helix to fit various outside diameters of casing (Fig. 3). The helix is slipped over a joint of casing and fastened by arc welding the metal base of the centralizer to the casing. One or more sections can be installed at any desired point or points on a string of casing. In some areas where large-diameter casing is adjacent to shallow sands which have become supercharged with gas, the helix, or so-called 'spiral' type of centralizer, is being used to make sure that the cement thoroughly surrounds the casing at critical points as an additional precaution against blow-outs. The steel strap in this centralizer serves as a base for welding it to the casing, while the flexible rubber extension will yield sufficiently to pass rough places in the well while the casing is being lowered.

Another type of casing centralizer used in some areas embodies several lengths of arched, flat, metal leaf springs spaced longitudinally and parallel to each other around the casing.

Weight, Viscosity, Yield-point, and Temperature of Circulating Fluid

Theoretically, if the weight of the circulating fluid were greater than that of the cement slurry, greater pump-pressure would have to be applied to force the cement slurry into and downwards through the casing, and a slightly less pressure would be required for completing the placement of the cement slurry behind the casing after it has equalized inside and outside the casing. This is apart from the effect of the viscosity of the mud and the effects of time and temperature on the consistency of the slurry. Following the same lines of reasoning, the lighter the circulating fluid the less the pressure required to pump the slurry to a point of equalization, but a greater pressure will be required to force the slurry farther. There are areas in which water is used as a circulating fluid, and when the cement slurry is pumped into the casing it immediately overbalances the water and causes suction in the upper end of the casing. In such cases a large amount of cement slurry can be pumped to equalization very quickly, but the surface cementing equipment must be capable of quickly building up very high pump-pressure, due to the fact that, after equalization of the slurry, a light fluid inside the casing is being used to displace a very heavy one outside the casing. In other areas a circulating fluid with a high yield-point and viscosity makes it necessary to apply pressure to introduce cement slurry weighing 16 lb. per gallon into the top of the casing to displace a mud weighing several pounds less per gallon.

Cements—Water/Cement Ratio, Setting Time, Contamination

The principal advantages of Portland cement in oil-well cementing are its economy, availability, generally uniform quality, and consistent effectiveness in protecting oil and gas by permanently preventing intrusion of upper waters and migration of oil and gas. It also prevents corrosion and collapse of the casing where cemented.

There are special cements, however, offering certain advantages under certain conditions at slightly higher cost. As these special cements have what may be called 'individuality', differing from Portland cement as well as from each other, the physical properties of each must be understood and applied accordingly. For instance, one characteristic of a special cement may be a finer grinding than Portland cement to give it more rapid hardening when mixed with water. The finer the particles the faster will be the association and hydration with water. Whatever the other properties or advantages of special cements, the most important factor in deep-well cementing is the time it takes for the cement to set sufficiently to be no longer moveable in a well. This setting time must be studied. If it is less than that of Portland cement, the latter is quite likely safer to use in cementing very deep wells (Fig. 4).

The deeper the well the more work is necessary in cementing the well in a given time. Also, the deeper the well the higher the working temperature. These two factors, affecting the setting time of cement, require that cementing equipment and procedure be co-ordinated accordingly, so as to place the cement slurry properly within the time allowed by the cement as affected by those factors.

Chemical acceleration has been used to hasten the hardening process of cement so that drilling operations could be resumed in a shorter time than previously allowed. The action of these accelerators not only hastened the hardening process, but also decreased the setting time. However, so long as the speed attained in mixing and placing cement was considerably faster than the setting time of the cement, there was considerable use of accelerators. When a depth was reached at which formation temperatures were sufficiently high to accomplish the same accelerating effect as the chemical accelerators, the latter were no longer used.

In cementing jobs where temperature conditions make it apparent that a retarding effect would be desirable, instead of an accelerating effect, the use of ice to chill the mixing water is a very practical physical method. A chemical retarding method has been worked out which also lengthens the setting time of the cement at high temperatures.

For oil-well cementing in general, a suitable range of water/cement ratios for Portland cements made in accordance with specifications of the American Society for Testing Materials, is between 4½ and 5½ U.S. gallons of water per sack of cement, weighing 94 lb (Figs. 5 and 6). When a large amount of cement is used in a well, the first part of the slurry may be mixed at a much higher water/cement ratio and the slurry then gradually thickened to the most desirable water/cement ratio, considering all conditions. The reason for thinning the first part of the batch is due to that part of the slurry scavenging mud ahead of the cement on its upward travel through the annular space behind the casing.

When it is desirable to lighten the weight of the cement slurry, it can be accomplished by increasing the water/cement ratio and adding just sufficient high-grade bentonite to keep the cement particles in suspension.

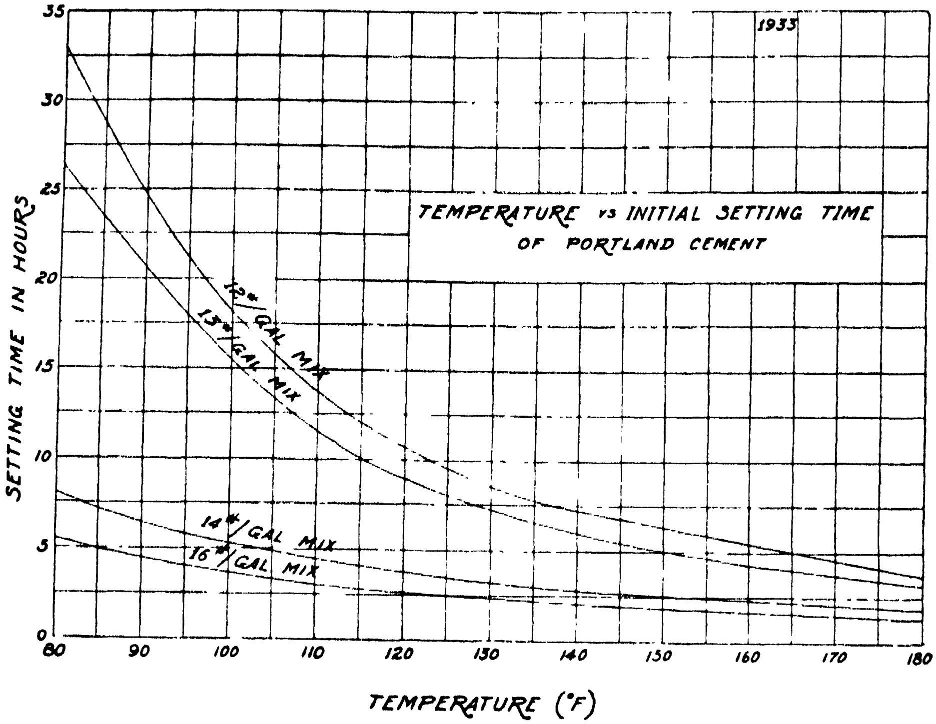

FIG 4.

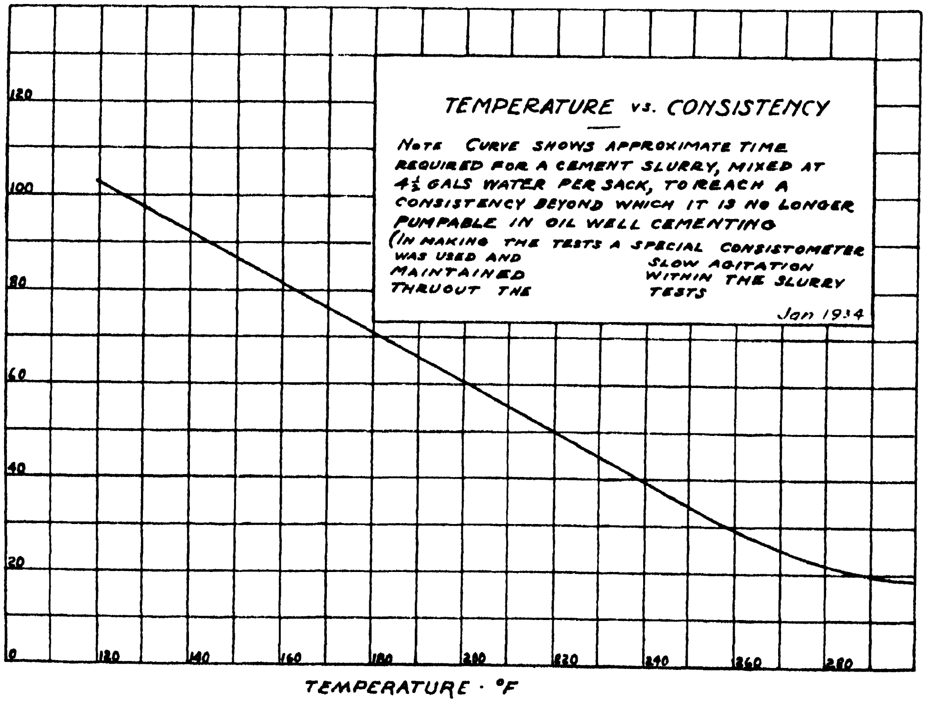

FIG. 5.

All cements used for oil-well cementing should be fresh and free from lumps. It is important that the sacks of

cement, when stored prior to use in oil-wells, be kept in dry warehouses, as contact with moisture causes caking and lumping.

Cementing Methods

Cementing Regular Casing Strings.

The most effective way of placing cement slurry behind casing in wells drilled with rotary tools, or cable tools with the hole full of fluid, allowing circulation around the casing, is by the two-plug method. This consists of placing a bottom cementing plug in the casing ahead of the cement slurry and a top plug after the slurry, thus enclosing the slurry between the two plugs and preventing contamination of the slurry; the slurry being forced downwards through the casing by circulating fluid which is pumped into the top of the casing. This method has been the basic standard of cementing casing for a number of years (Fig. 7).

At the time this method was first introduced the use of float valves in the pipe was unknown. The bottom or lower cementing plug was pumped out of the casing, and the top cementing plug stopped on top of the lower plug after the slurry had been forced into the space behind the casing, but the upper part of the top plug remained inside the casing, thus stopping the pump at the surface and indicating that the cement had all been placed on the outside of the casing. Practically all the slurry was pumped out of the casing, including the 'washed' cement on top of the column. In present practice this 'washed cement' is left inside the casing and is readily drilled and circulated out of the well when the cementing plugs are drilled.

The measuring device was later introduced to oil-well cementing for continuously measuring the position of the top cementing plug during its descent through the casing. When the measuring line shows that the top cementing plug has reached the desired level in the casing the pumps are shut down. The line will also show the position of the cement in case the top plug is prematurely stopped by a casing leak or an obstruction.

Later, the use of float valves in the pipe created a demand for a specially designed bottom cementing plug that would stop on top of the float valve and yet would allow the cement slurry to pass by

In wells being drilled by cable tools with little or no circulating fluid in the hole when running casing, the cementing is usually done by what is called a 'balanced' method. The cement slurry is mixed and pumped into the empty casing and falls to the bottom. A top cementing plug is placed in the casing and forced downwards by water above it. The travel of the plug is measured by the measuring line, and sufficient water is allowed to fall on top of the plug until the cement slurry is balanced around the shoe and in the space behind the casing.

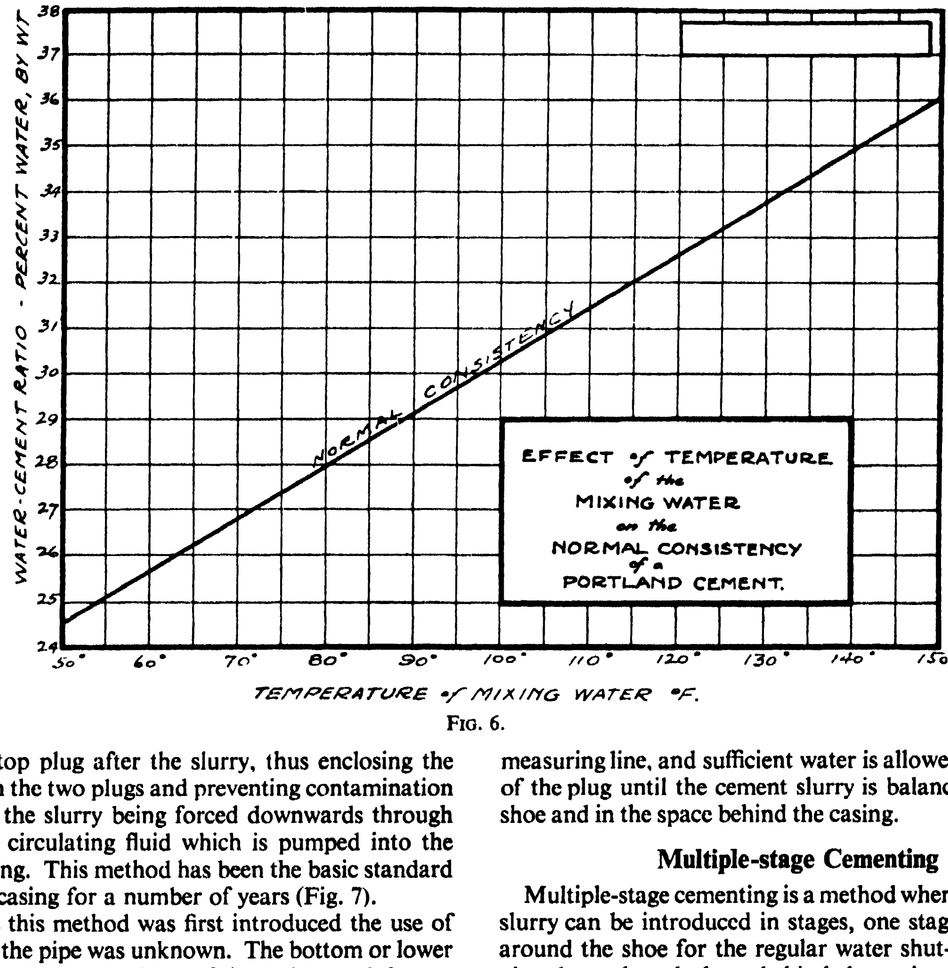

FIG. 6.

Multiple-stage Cementing

Multiple-stage cementing is a method whereby the cement slurry can be introduced in stages, one stage being placed around the shoe for the regular water shut-off and others placed at selected places behind the casing. Very often a gas- or oil-producing sand is encountered at shallow depths, but for commercial reasons the well is drilled to deeper producing horizons. Multiple-stage cementing makes it possible to 'spot' a stage of cement slurry adjacent to shallow gas or oil formations, affording protection against intrusion of water from above and below, and conserving them for future production. This method also provides means for 'spotting' a stage of cement as protection against blowouts from high-pressure gas or oil sands located behind the casing (Figs. 8*a* and 8*b*).

Although especially applicable to cementing in deep wells, multiple-stage cementing is useful in wells of any depth where conditions make high pump-pressures necessary to place large amounts of cement. For example, in the cementing of 3,600-ft. strings of casing from top to bottom, in the East Texas field, under regular cementing procedure, pump-pressures of around 1,500 lb. per sq. in. were necessary, whereas on similar casing jobs in the

same field using multiple-stage cementing, the casing was cemented from top to bottom, but the pump-pressure did not at any time exceed 500 lb. per sq. in.

There have been other areas in which deep oil production is the reason for drilling the wells, but shallow gas production lies behind the casing at a point above the amount of cement slurry that is desirable or possible to place around the shoe. In such cases the multiple-stage cementing device was placed in the casing below the gas sand and a stage of cement slurry spotted to protect and conserve the gas, also to protect against damage from the gas blowing out.

In deep wells of the future multiple-stage cementing will make cementing operations considerably easier on long strings of casing.

Full-hole Cementing

Full-hole cementing is a modern method of cementing a combination string of casing, which is a string consisting of blank casing in the upper portion and screen or perforated liner, of practically the same diameter as the casing, in the lower portion (Figs. 9*a* and 9*b*). The practice provides a number of important advantages over reduced hole practice in which casing is set, a small hole drilled, and a small liner set in the sand. Before the development of full-hole cementing the practice of running and cementing combination strings lacked adequate means for circulating down through the screen or perforated section of the casing for the purpose of washing cavings, cuttings, or heavy detritus from behind the screen or perforated section. As an accessory to full-

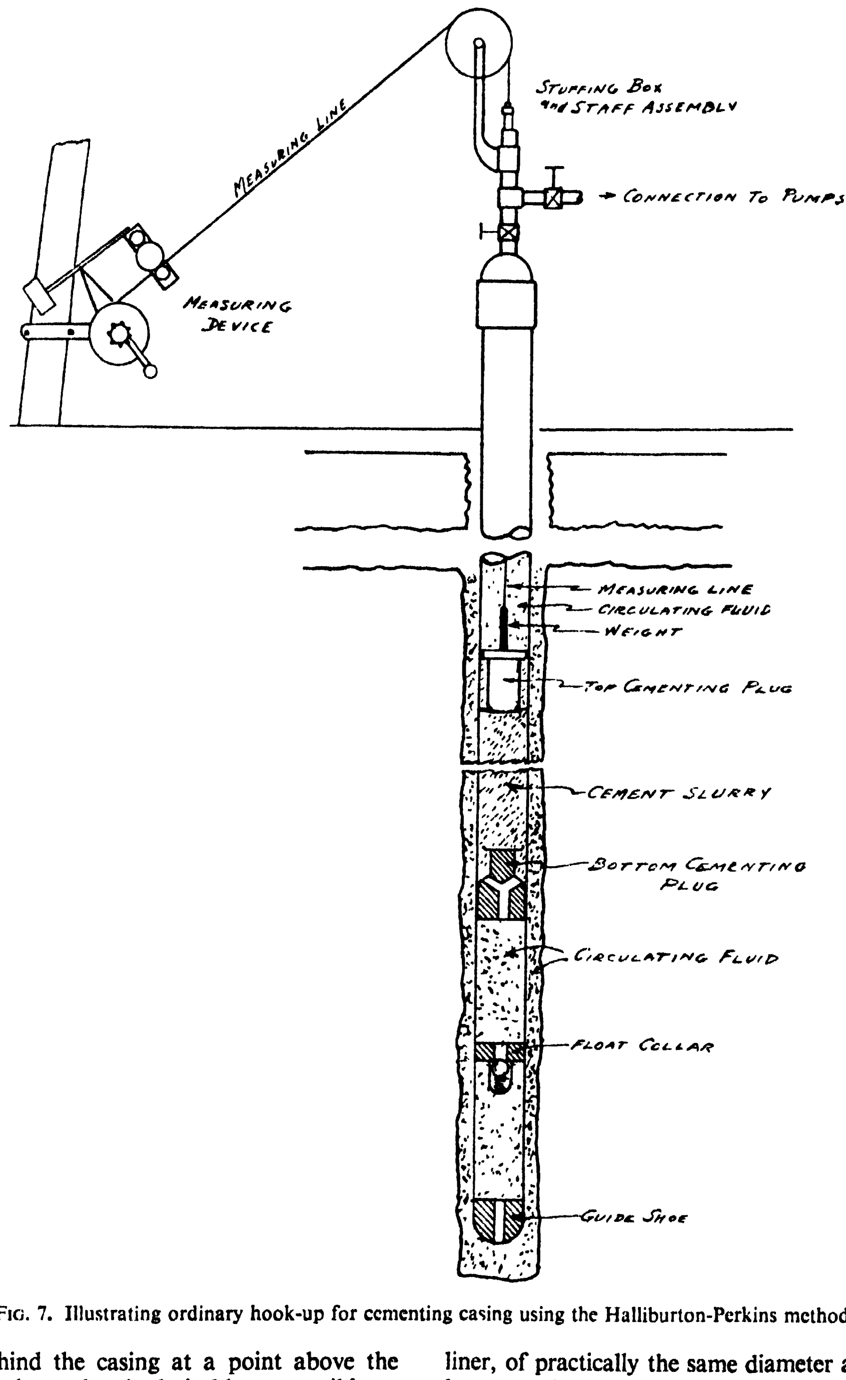

FIG. 7. Illustrating ordinary hook-up for cementing casing using the Halliburton-Perkins method.

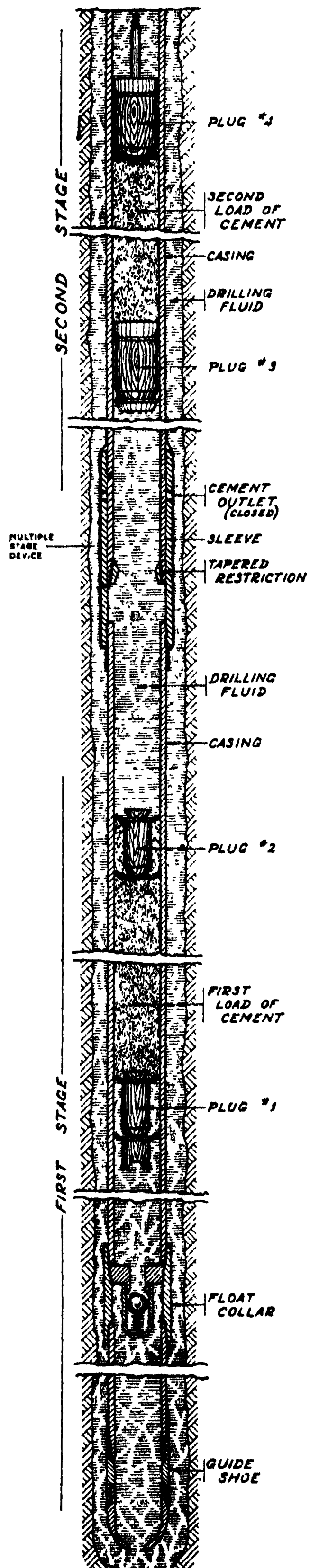

FIG. 8*a*.

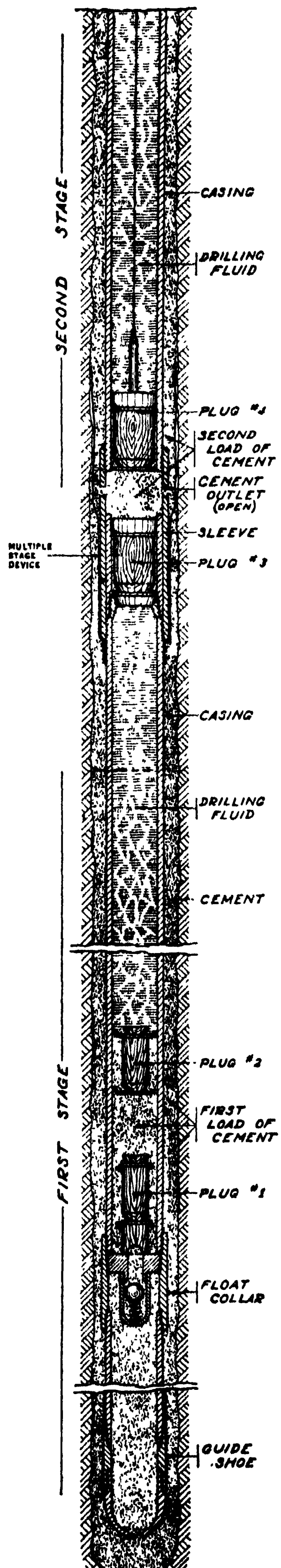

FIG. 8*b*.

Multiple-stage Cementing. Illustrating use of this method to facilitate placing large amounts of cement behind casing. There are other uses, among them the 'spotting' of a batch of cement to protect and conserve an upper sand.

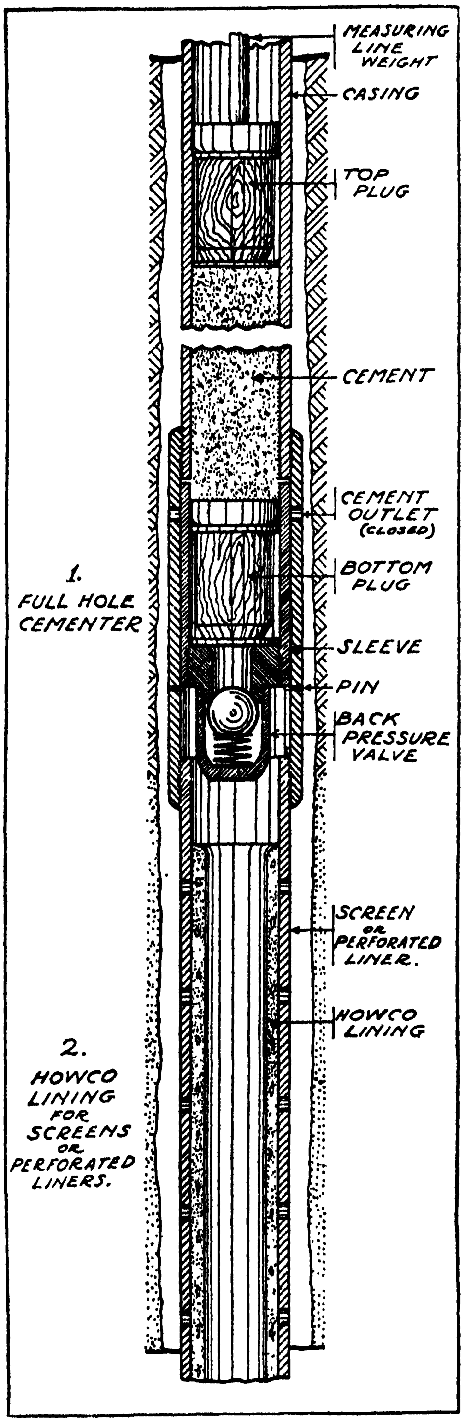

FIG. 9*a*. Operation of the Full-hole Cementer. Drawing shows device in 'closed' position with the sleeve covering the cement outlets, the sleeve being held in place by shear pins. Drilling fluid is circulated down through the device and Howco Lining to thoroughly wash the space outside the screen. Then a regular two-plug cementing job is done. Drilling fluid is not shown in drawing.

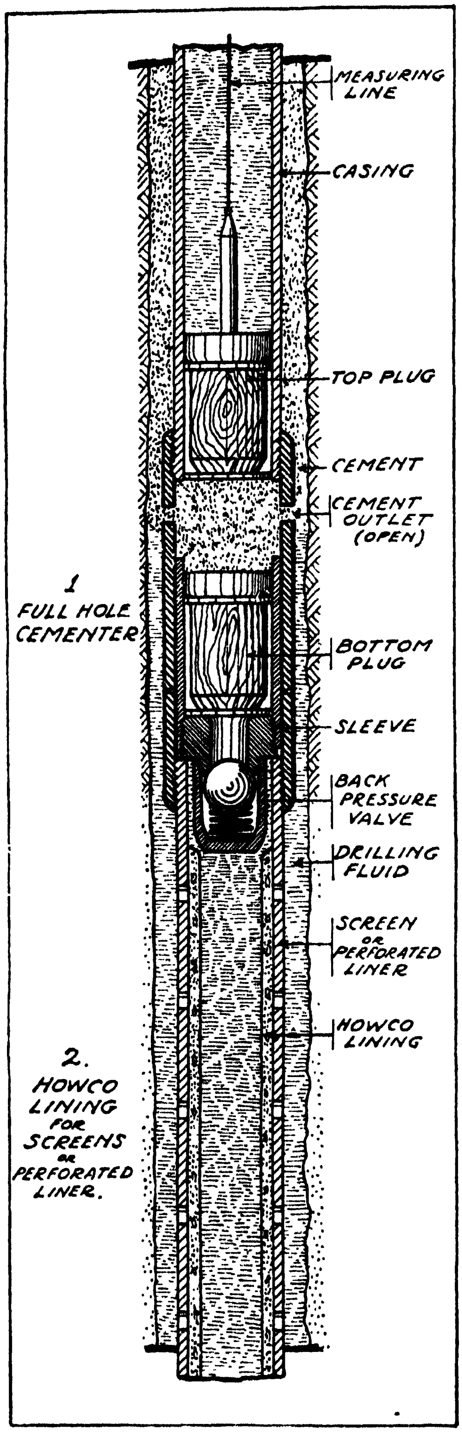

FIG. 9*b*. Operation of the Full-hole Cementer. Drawing shows device in 'open' position. The sleeve has been forced down by the bottom plug, uncovering the cement outlets and allowing the cement to pass through the outlets up into the annular space behind the casing. If an operator desires to use a canvas 'shirt-tail' packer, he can attach it to the liner just below the device. After the cement has set, the plugs, back-pressure valve, and Howco Lining are drilled out.

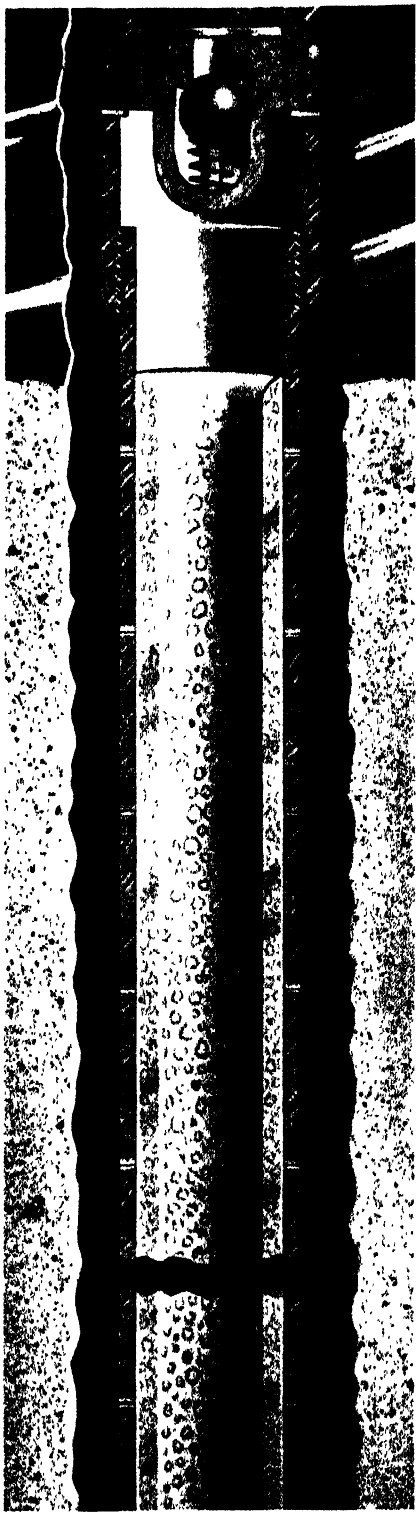

FIG. 10. Cement 'wash-pipe' lining for perforated liners on screens

hole cementing, a cement lining has been developed for the inside of the screen or perforated section to either direct the washing fluid down through the entire length of perforated casing or to prevent mud particles from being forced into the fine mesh of the screen (Fig. 10).

Full-hole cementing is especially essential to deep wells in which small-diameter production strings of great length are run. For example, a 9,130-ft. combination string, consisting of 9,020 ft. of 5¾-in. O.D. casing and 110 ft. of 5¾-in. O.D. screen was cemented by the full-hole cementing method. In one continuous operation, the casing and full-size screen was run, circulation established and equalized, cavings, cuttings, and heavy detritus washed from behind the screen, and the casing cemented. All that was necessary to complete the well, after waiting for the cement to harden, was to run the regular production string of tubing equipped with a diamond-point bit to drill out the obstructions in the casing and the cement lining in the screen, hook up the Christmas tree, and bring in the well. This required only a few hours. On the other hand, were regular reduced-hole practice used on this well, after the cementing job and the usual wait for the cement to set, there would have been a number of very difficult operations necessary inside the small casing, including coring, running screen, &c. The full-hole cementing method eliminated the necessity of hauling and making up almost 2 miles of small drill stem to make a number of difficult and hazardous round trips into the long, small casing, and open hole in the well.

Full-hole cementing is not only applicable to long strings, but also provides advantages to production recovery in shallower wells in which screens or perforated liners are run. It provides maximum drainage surface in the sand and considerably greater screen area. Such wells can be readily deepened without the necessity of cutting and fishing screens. It eliminates the necessity of hauling and making up small drill stem, also eliminates the expense of a number of final drilling operations incident to running screens and completing a well, making it possible to have the well on production considerably sooner. As a result of full-hole cementing, a great many wells have been completed by using the producing string of tubing equipped with a small diamond-point bit to drill out the cementing plugs and aluminium float valve. After functioning to clear the casing and screen, the tubing is not pulled. The Christmas tree is immediately installed, the drilling fluid flushed out of the hole, and the well brought in. The tubing is left in the well as the regular flow string.

Full-hole cementing has not only simplified completion practice, but from a standpoint of economy it has made possible a choice of either considerably reducing the initial cost per well or reducing slightly the cost per well and ultimately yielding considerably more income, according to the size of the casing selected. For example, in the East Texas field, where many thousands of wells have been drilled in the last few years, initial cost has been considerably reduced on a number of wells where full-hole cementing has been used by making the size of the casing the same size as the screen which had been run. In reduced-hole practice where 5-in. O.D. screen and 7-in. O.D. casing had been run, some operators changed the programme to full-hole cementing practice, using a combination string of 5-in. O.D. casing and screen. It was felt by those operators that as there was no likelihood of the wells being drilled to deeper sands at some later date, requiring another string of casing, the small-diameter casing would be adequate for production purposes. They felt justified in saving the difference in cost between 7-in. O.D. casing and 5 in. O.D. casing and between 9⅞-in. hole and 7⅞-in. hole, as well as some additional economies in size of surface casing, &c. As a matter of fact, the drainage surface in the sand was greater in these wells with 5-in. O.D. casing and screen and 7⅞-in. hole in the sand than if they were completed with 7-in. casing and 5-in. O.D. screen set in 6⅛-in. hole. The initial cost per well was reduced about one-third.

On the other hand, some East Texas operators considered it advisable to use full-hole cementing practice, continuing with 7-in. casing, but drilling 9⅞-in. hole into the sand and running 7-in. O.D. screen on bottom of the 7-in. casing. In this manner, due to the elimination of small drill stems and other items, as well as saving time, the initial cost per well was actually decreased, and approximately 63% more drainage surface obtained in the sand and 40% more screen area. In fact, the same amount of drainage surface and screen area was obtained as if 10¾-in. O.D. casing had been actually set on top of the sand and 9⅞-in. hole drilled into the sand. The factor of increased drainage surface and screen area has an especially important relation to ultimate yield and to ease of producing the last few thousand barrels of recoverable oil per acre. In many cases, actual profit on original investment depends upon economical recovery of the last few thousand barrels per acre.

Methods have been devised for working over the wells completed by this method. Perforation cleaners of various types are used for cleaning perforations, and successful results have been obtained in plugging back. Then, when it is desired to deepen a well, no expensive preliminaries are necessary, such as cutting and fishing liners.

Cementing Leaky Casing

Whenever there is an indication of a casing leak, the exact location of the leak is first determined by pumping a test plug, which is very similar to a cementing plug, down the casing, following the descent of the plug by means of the measuring line. The plug stops at the casing leak, the exact depth being shown by the measuring line.

After locating the leak, pump-pressure is applied on the inside of the casing in order to break circulation. If free circulation is obtained a cementing job is done similar to that which is done around the shoe on a regular string of casing. The amount of cement used depends upon the pump-pressure necessary to maintain circulation. In cases where circulation is not free but the hole takes fluid through the casing leak, then a so-called 'squeeze' job is attempted. Squeeze jobs are usually done through tubing in various ways. In cases where the hole does not take fluid below the casing leak a squeeze job is done without a barrier being placed below the leak. If, however, the hole below the casing is likely to take fluid under pressure, then a bridge plug and cement barrier is placed inside the casing just below the leak. This is done by putting a bridge in the casing below the leak and then placing sufficient cement on top of the bridge to prevent flow of fluid under pressure down through the lower part of the casing.

After the lower barrier is set, one method of doing a 'squeeze' job is to run tubing until the bottom of the tubing is just above the level of the casing leak. The top of the tubing is suspended on a casing head equipped with a stuffing-box arrangement so that the tubing can be moved while under pressure. The casing-head valve on the casing is open and circulation established down through the tubing. Cement slurry is then introduced into the tubing, and after a calculated amount of slurry is pumped into the

tubing to almost fill the tubing, the casing-head valve is closed and the only course for the slurry to travel is out through the bottom of the tubing and through the leak in the casing. When a sufficient amount of slurry is forced through the leak, or until the pump-pressure required to push the slurry out through the leak becomes so great that it endangers the casing, the tubing is raised several feet through the stuffing-box and the excess cement in the tubing is washed out to the surface by 'reverse' circulation down through the casing and back through the tubing. Back-pressure may be maintained on top of the tubing by means of a partially closed valve. After the excess cement is washed out of the tubing the tubing is removed.

Another method of doing the squeeze job is similar to that just described, but on the bottom of the tubing a device called a 'cement retainer' is placed. This device consists primarily of a cast-iron body, rubber packer, slips, and a back-pressure valve which allows circulation down through the tubing, but prevents the fluid from returning. The cement slurry is pumped down through the tubing, out through the valve in the bottom of the retainer, and through the casing leak. The tubing is then detached from the retainer and raised or pulled. The back-pressure valve in the retainer prevents the slurry from flowing back through the retainer. The retainer is drilled out when the cement has hardened.

Plugging Back with Cement

There has been considerable interest shown in cementing operations for shutting off bottom water, whipstocking, and other purposes.

Before describing specific methods, there has been occasional use of preliminary operations intended by operators to improve the results from plug-back operations.

One of them is to discharge a nitroglycerine shot at the upper portion of the formation to be plugged off. One purpose of the shot is to make a pocket, or wide place in the hole, to assist the cement to withstand against thrust-pressure of the water against the bottom of the cement plug after the well is again put on production.

Another method, intended for a similar purpose, is by under-reaming a wide place in the hole by means of a rotary wall-scraper. In one well in which this device was used there was a water sand at the bottom of the well immediately below the cap-rock, above which was the oil sand. Before the plugging-back operation, the water sand was under-reamed in an attempt to get a square shoulder on the underside of the cap-rock. The purpose of the square shoulder was to make it more difficult for the water to break in over the top of the cement plug after the well was put on production, and also for the purpose of providing a more secure anchor for the cement plug against the thrust-pressure of the water at the bottom of the cement plug.

As an aid to calculate the amount of cement that may be required to fill a given amount of hole to be plugged back, a device has been developed for measuring and recording the irregularities and cavities in open holes. It is referred to as an open-hole recording caliper, and consists of a steel shell, 5 in. in diameter, which encloses a recording mechanism that receives impressions from four movable arms that make sliding contact with the wall of the hole. The arms operate a ratchet which raises and lowers a recording stylus against a chart. Each arm registers its own radius. The device is run into a well on a steel measuring line. When the device is being lowered in the well the arms are folded inside the shell. The arms can be arranged to trip into open position when the device reaches bottom. The device is then raised slowly, allowing the arms to register.

Whether or not such special devices or methods are used, it is obviously essential that before starting a plug-back operation the bottom of the hole should be cleaned as thoroughly as possible so that the cement slurry will make a good bond with the grains and pores of the formation to be plugged off.

There have been a number of plug-back methods with various adaptations for special conditions, but the following are representative of those now being used.

'Balanced' Method of Plugging Back.

In using this method, the tubing or drill pipe is run to the bottom of the well and then raised about a foot off bottom. Circulation is then established and maintained until the circulating fluid is equalized. A calculated amount of cement is then pumped into the tubing, followed by circulating fluid. This method depends upon the excess weight of the cement slurry over that of the circulating fluid causing the cement to equalize on the outside and inside of the tubing or drill pipe at the bottom of the well. It is essential that the circulating fluid pumped into the tubing after the cement slurry be the same kind and weight per gallon as that in the well on the outside of the tubing. In order to prevent any vacuum from affecting the equalization of the cement slurry the upper end of the drill pipe and the upper end of the casing are both opened to atmospheric pressure.

After the cement has equalized inside and outside the lower end of the tubing, the tubing is raised to a point just above the intended top level of the plug-back and the excess cement circulated out of the well, either by circulating down through the tubing and up through the space between the tubing and the casing, or by reverse circulation down through the casing and up through the tubing or drill pipe. Some operators prefer to use regular circulation down through the tubing when the lower end of the tubing is in open hole in which there are formations which tend to cave, and it is feared that if reverse circulation were used the fluid passing down through the casing and the open hole might cause a greater tendency for the formations to cave. However, regular circulation takes longer to wash the excess cement from the well. Reverse circulation, on the other hand, removes the excess cement from the well in considerably less time, which is important in deep wells.

The tubing is then raised to a safe level or withdrawn from the well, and the cement is allowed to set before operations are resumed.

Displacement Method.

This method is somewhat similar to the balanced method, except that a measured amount of fluid is pumped into the tubing or drill pipe immediately after the cement slurry and the tubing or drill stem need not be opened to atmospheric pressure at the surface.

The simplest form of carrying out a displacement job, after the tubing is run to bottom, raised a foot off bottom, the mud equalized, and the cement slurry pumped into the top of the tubing, is to pump in sufficient circulating fluid to fill all the tubing or drill pipe except the lower portion, which is temporarily left filled with cement. The amount of cement left in the bottom of the tubing depends upon the amount of hole to be plugged back, sufficient cement being left in the bottom of the tubing to make sure that

there is no contamination of the cement when the tubing is raised. If no cement were left in the bottom of the tubing, there would be contamination of the cement slurry by the circulating fluid when the tubing is raised.

The tubing is then raised to a short distance above the intended top level of the plug-back and the excess cement is washed out of the well by regular or reverse circulation. The cement is then allowed to set before operations are resumed.

Although that form of displacement method has been widely used with considerable success, there are variations to meet special conditions (Fig. 11).

Plug Methods.

Several plugging-back methods have been used which involve the use of cementing plugs made of wood or other material placed in the tubing before or after the cement slurry, or both before and after. While the displacement method has been more generally used than the more complicated plug methods, yet some operators have felt that

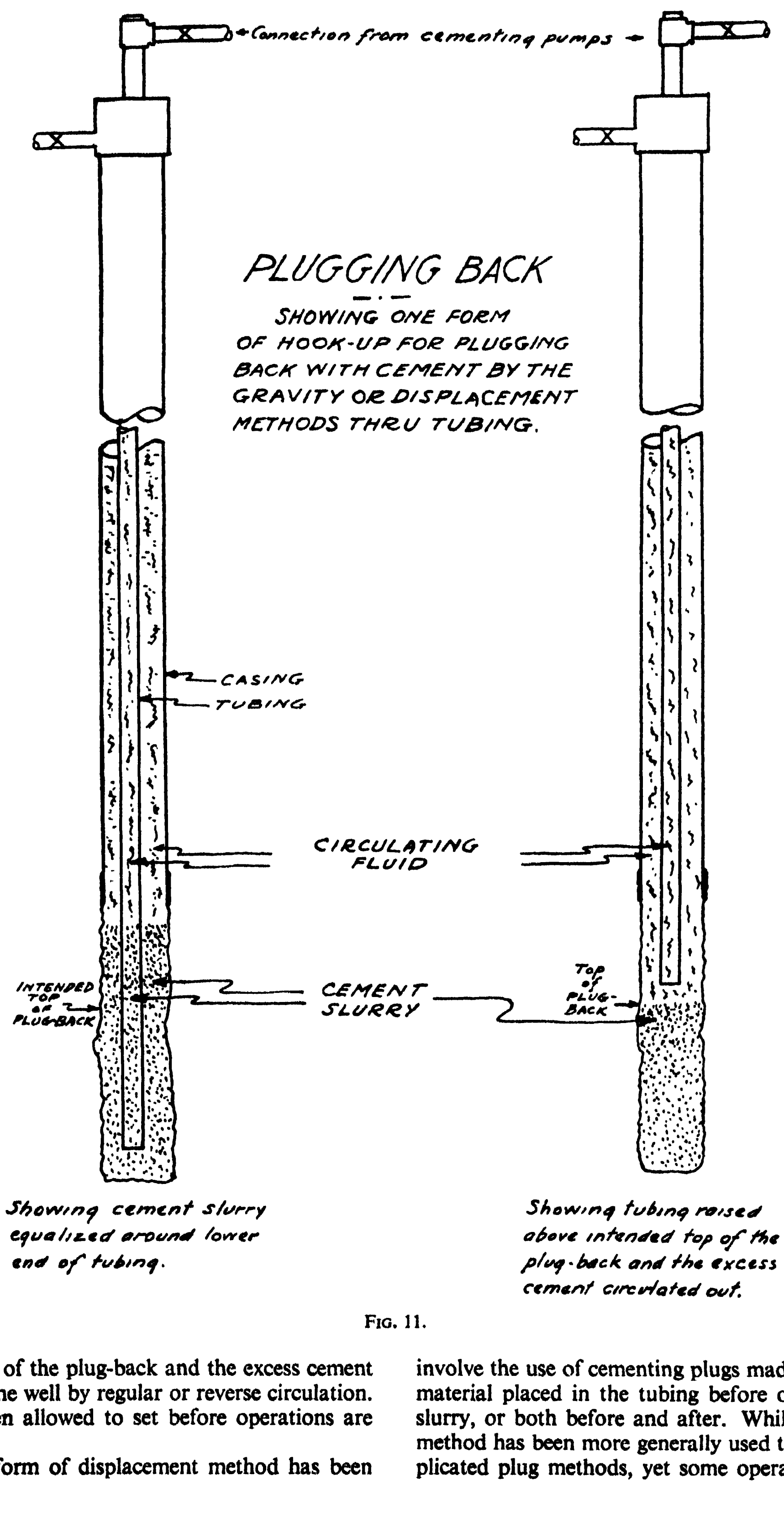

FIG. 11.

special conditions would make the use of a plug method more desirable.

One method of using plugs is to run the tubing to the bottom of the well and then raise it until the bottom of the tubing is a few inches above the bottom of the well. A wooden cementing plug about 2 ft. long is then placed in the top of the tubing. The required amount of cement slurry is pumped into the tubing and then another wooden cementing plug about 3 ft. long, equipped with a leather cup on the upper end, is placed in the tubing. A sufficient amount of cement slurry is then pumped into the tubing on top of the second cementing plug calculated to fill the lower end of the tubing up to a point above the intended top level of the plug-back. This column, consisting alternately of wooden cementing plugs and cement is pumped down through the tubing until the first cement plug strikes the bottom of the well, shutting down the pump at the surface. The tubing is then raised 2 ft. to allow the first cementing plug to pass out of the tubing. The tubing is then lowered again and the cement is pumped around the lower end of the tubing until the second cementing plug strikes the bottom of the well, shutting the pump down. The tubing is then raised to a point about two feet above the intended level of the plug-back and reverse circulation established, washing out the excess cement.

Another method involves the use of a special plug consisting of two swab cups on a mandrel and a seating shoe. A perforated bull plug, a collar with a valve seat for the special cementing plug, and a working barrel are placed on the bottom of the tubing. The tubing is run to bottom and the well washed through the perforated bull plug. The required amount of cement slurry is pumped in the tubing, followed by the special cementing plug. Circulating fluid is then pumped into the tubing until the cementing plug reaches the assembly on the bottom of the tubing, at which time the seating shoe of the plug seats in the valve in the collar, shutting down the pump at the surface and indicating that all the cement slurry is outside of the tubing. The tubing is then raised the required distance and circulating fluid is pumped into the casing, reversing the circulation and forcing the special cementing plug and excess cement up through the tubing to the surface. To expedite the recovery of the special cementing plug, a chamber is previously installed on top of the tubing. This chamber consists of a tubing nipple long enough to hold the cementing plug, with a tee and a side outlet at the bottom end of the nipple and a gate valve below the tee.

There are several other adaptations of the plug method, but they are seldom used.

Squeeze Jobs.

The name 'squeeze', when applied to cementing jobs, means that the cement is forced, or 'squeezed', into a formation or through perforations or leaks in the casing. When using this 'squeeze' principle in plugging-back operations the tubing is run to the bottom of the well and raised a few inches off bottom and the casing head is connected up between the casing and the tubing at the surface. With the casing head open, circulation is established and maintained until the circulating fluid is equalized, after which the required amount of cement slurry is pumped into the top of the tubing. If the amount of cement slurry pumped into the tubing is sufficient to fill all the tubing, then the casing head is closed when the lower end of the cement column reaches the bottom of the well. If the amount of cement slurry is not sufficient to fill the tubing, circulating fluid is pumped into the tubing after the cement slurry. In either case, the casing head is closed as soon as the bottom of the cement column reaches the bottom of the well. With the casing head closed, and by pumping circulating fluid into the top of the tubing, the only place for the cement slurry to go is out into the voids or erosions in a permeable formation. If the formation takes the cement slurry, pumping is continued either until a pressure limit has been reached or until the cement slurry has been pumped out of the tubing, except a sufficient amount left in the tubing to prevent contamination when the tubing is raised. The pressure is then released at the casing head and the tubing raised to a point just above the intended top level of the plug-back and reverse circulation established to wash the excess cement out of the well. The tubing is then raised several hundred feet and the casing head closed and pressure applied. The well is shut in under pressure until the cement has had time to set sufficiently to resume operations.

In another adaptation of the 'squeeze' job the mechanical hook-up is similar to that just described, except that a stuffing-box arrangement is installed on top of the casing at the surface through which a joint of tubing or drill pipe about 30 ft. long can be raised or lowered. The tubing is run to bottom and raised about a foot off bottom. Sufficient water is then pumped into the tubing to fill all the tubing and space outside the tubing at the bottom of the well up to a point just above the intended top level of the plug-back. With only a 30-ft. stroke through the stuffing-box at the surface the plug-back is limited to less than 30 ft. from the bottom of the well. If it is necessary to plug back more hole it can either be done in stages or several joints of flush joint tubing or drill pipe can be used to work through the stuffing-box. After the water has been placed, the casing head below the stuffing-box at the surface is shut in. Water is then pumped into the top of the tubing and the only place for the water to go is out into some open formation at the bottom of the well. Inasmuch as the reason for doing a plug-back job of this type is usually for the purpose of shutting off water coming from a formation or part of a formation in the bottom of the well, the water pumped in under this method will usually first go out into the water-bearing portion of the formation. By watching the amount of pressure required to force water out into the formation the amount of cement to be used can be approximated. The cement slurry is then pumped into the top of the tubing and, if the pump-pressure is somewhat high at that time, slowing up the pumping of the cement down the tubing, the casing head may be opened until the bottom of the cement slurry reaches the lower end of the tubing. The casing head is then closed, and the only place for the cement slurry to go is to follow the water into the formation. By again watching the increasing pump-pressure required to force the cement out into the formation the pump can be stopped as soon as it is felt that the cement has been 'squeezed' sufficiently into the formation and that none of it has been pumped into the oil-bearing formation. The tubing is then raised through the stuffing-box, still under pressure, to a point about a foot above the intended top level of the plug-back and reverse circulation established down through the casing, up through the tubing, and out through a valve at the top of the tubing, the valve being adjusted to maintain a suitable back-pressure while the circulating fluid and excess cement are circulated out of the tubing. When the excess cement is washed out of the tubing the valve is closed and an equal pump-pressure, up to the amount required to 'squeeze' the cement in the formation,

is applied on both tubing and casing, if felt necessary. The cement is then allowed to set before operations are resumed.

Plugging Back in 'Thirsty' Formations.

Unlike conditions where a 'squeeze' type job is necessary to force cement slurry into a formation, there are jobs which require plugging back in 'thirsty' formations which are sufficiently permeable to take the cement slurry without any pressure other than the hydrostatic pressure of the cement slurry and the circulating fluid. As an example, in one recent plug-back job of this type it took 300 sacks of cement to plug back 30 ft. of a hole that had been cut by a $6\frac{1}{8}$-in. bit.

When plugging back in 'thirsty' formations there are three general methods now being used. One of them is to use regular cement slurry and make successive plug-back jobs by displacement or other suitable method using a small amount of slurry in each job and allowing an interval of several hours between each job. Another method is to lighten the weight of the cement slurry by using a cement-bentonite mixture. The latest method, however, is to use a self-sealing cement, which contains a fibrous sealing material premixed with the cement in dry state at the cement plant. The idea of the latter material is that when the cement starts going out into the formation, the fibrous materials begin building a seal against further entry of the cement slurry.

Plugging Back in Screens or Perforated Liners.

When a screen or perforated liner is in a well to be plugged back, and is not easily removed, cement can be placed in the lower part of the liner back to the desired level by the displacement method. This procedure is not only the least expensive by far, but, if properly done, can be made as effective as plug-backs made in the water portion of a continuous sand body, especially when the flowing conditions in the well, when on production, are controlled so that there is a small differential flowing pressure adjacent to the cement plug.

When the water sand at the bottom of a well is separated from the oil sand by impermeable formations, and the screen or liner is not easily removed, and it is desired to separate the sands with cement, cement can be placed outside the liner through perforations by an adaptation of the 'squeeze' method. Cement is left inside the liner to the desired level.

Summarizing the above, in order to get the most successful results from cementing operations it is necessary to first condition the well for the job, select the equipment and method that appear most suitable for the conditions in the well, use fresh cement that is free of lumps, mix the cement with fresh water and within the range of proper water-cement ratios, place the cement slurry in the well with the least amount of contamination, see that no agitation of gas or fluid movement disturbs the cement slurry after it has been placed and before it sets, and allow the cement to set sufficiently before resuming operations.

PROPERTIES OF CEMENTS

By the late S. G. S. PANISSET, A.C.G.I.

Chief Chemist, The Associated Portland Cement Manufacturers, Ltd.

THE cements in common use for constructional and allied purposes are in the following categories: (*a*) Portland cement, (*b*) rapid-hardening Portland cement, (*c*) aluminous cement, (*d*) pozzolana cement, (*e*) slag cement. Typical analyses are as follows:

	Portland cement	*Rapid-hardening cement*	*Aluminous cement*	*Pozzolana cement*	*Slag cement*
Silica	22·4	20·7	4·8	38·6	24·4
Insoluble matter	0·2	0·2	..	..	0·4
Alumina	7 1	6·5	39·7	10·2	9·2
Iron oxide	2·9	3·1	16·9	4·4	1·9
Lime	62 7	64·4	38·2	41·7	57·4
Magnesia	1·0	1·1	0 4	1·8	2·2
Sulphuric anhydride	1·5	1·9	..	1·2	1·6
Sulphur as sulphide	..	..	..	..	0·6
Loss on ignition	1·5	1·5	..	1·1	1·5
Alkalis, &c.	0 7	0·6	.	1·0	0·8
	100·0	100·0	100·0	100·0	100·0

Portland cement is manufactured by calcining to the point of incipient vitrefaction (1,400° to 1,600° C.) a finely divided mixture in certain proportions of calcareous and argillaceous materials and grinding to a fine powder the calcined product with a small proportion of gypsum. During the calcination the lime, silica, alumina, and iron oxide in the raw material mixture combine to form the following compounds: tricalcium silicate ($3CaO \cdot SiO_2$), dicalcium silicate ($2CaO \cdot SiO_2$), tetracalcium alumino-ferrite ($4CaO \cdot Al_2O_3 \cdot Fe_2O_3$), and tricalcium aluminate ($3CaO \cdot Al_2O_3$). The relative proportions of these compounds in any one cement naturally depend on the ratios of their primary constituents, lime, silica, alumina, and iron oxide in the raw mixture; but as tricalcium silicate contributes more to the strength of cement than the other compounds, the cement manufacturer adjusts the percentage of lime to give a reasonably high proportion of this compound. Normal Portland cements come within the following range:

Tricalcium silicate ($3CaO \cdot SiO_2$)—30 to 40%.
Dicalcium silicate ($2CaO \cdot SiO_2$)—30 to 40%.
Tetracalcium alumino-ferrite ($4CaO \cdot Al_2O_3 \cdot Fe_2O_3$)—5 to 15%.
Tricalcium aluminate ($3CaO \cdot Al_2O_3$)—10 to 20%.

Other constituents of Portland cement in small proportions and of minor importance are magnesia, up to 4%; potash and soda, up to 1%; and calcium sulphate, up to 4% The last-named is derived from the gypsum incorporated during the final grinding process of the cement, and is necessary for retarding the setting of the cement to allow sufficient time for mixing and depositing the concrete or mortar in which it is used.

Rapid-hardening Portland cement is manufactured in the same way as Portland cement, but with certain refinements such as finer grinding of the raw mixture and of the finished cement; a higher proportion of lime is also needed to raise the proportion of tricalcium silicate and so increase the strength of the cement. These measures are principally effective in expediting the development of strength, and consequently concrete made with rapid-hardening cement is as strong at 3 or 4 days as one made with normal cement at a month.

Aluminous cement is made by heating to fusion-point a mixture of lime and bauxite (a mineral of high alumina content) and grinding the fused product to a fine powder. The essential compound in aluminous cement is monocalcium aluminate ($CaO \cdot Al_2O_3$), but dicalcium silicate, tetracalcium alumino-ferrite, and other compounds are also present in minor quantities.

Pozzolana cement is a mechanical mixture of Portland cement and a material containing silica in such a form that it will combine with lime in the presence of water at a normal temperature. This material may be either a volcanic ash or a high silica clay that has been kiln heated to a definite temperature. The term pozzolana is used because the Italian town of Pozzuoli has been a source of suitable volcanic ash for many centuries, but similar materials are named Trass in Germany, Santorin Earth in Greece, Gaize in France, and Moler in Scandinavia. In England there is no suitable volcanic mineral, and artificial pozzolana is made by calcinating selected clays at appropriate temperatures.

The function of pozzolana when mixed with cement is to provide silica which will combine with the lime liberated by the latter in the process of setting and hardening. By this means a soluble (and therefore undesirable constituent) is removed from the set cement, and the latter is made more resistant to the otherwise destructive action of sea-water and other sulphate solutions.

The proportion of pozzolana in a pozzolana cement varies in accordance with the strength requirements of the concrete in which it is to be used, but 40% is a common figure.

Slag cement is a mechanical mixture of Portland cement and blast-furnace slag in proportions ranging from 30% to 70% of either constituent. Suitable slags have slight hydraulic properties and thus contribute to the strength of the mixture. Slag cements contain less lime than Portland cements, and are considered more resistant to the corrosive action of sulphates and other salts.

Strength of Cement. In practice cement mortars and concretes are generally used for their power of resisting compressive stresses, and, strictly speaking, the strength quality of cement should be judged by its compression strength when mixed with the proportions of sand and aggregate commonly adopted in constructional work. For comparative purposes such a test requires the use of a standard aggregate which is difficult to define, also of a large compression testing machine which is a costly apparatus.

The strength of cement is therefore usually judged by its resistance to tensile or compressive stresses when mixed with three times its weight of sand of definite size. In Great Britain the tensile test is adopted as standard, but in many other countries the compression test is preferred because it

corresponds more closely to the stress which concrete receives in practice. The mixture of cement and sand with the proportion of water needed to give a standard consistency is filled into moulds of figure 8 shape, with 1-in. minimum section in the case of tensile tests and of 70-cm. cubes in the case of compression tests; the periods of ageing before testing range from 1 to 28 days. The consistency of the cement-sand-water mixture has an important bearing upon the result of the test. In British practice the consistency specified involves the use of a minimum proportion of water—usually about 32% of the weight of the cement—and consequently high test results are obtained. The same cement tested by the American standard would give lower test figures, because the consistency specified involves the use of 40% or more of water. Hence test results of cement obtained by the application of different national standard specifications are not comparable. The standard specification strength requirements for ordinary Portland cement of the more prominent cement-producing countries are summarized as follows—the cement being mixed with 3 parts of a standardized sand in every case:

	Tensile tests lb. per sq. in.			*Compression tests lb. per sq. in.*	
	3 days	*7 days*	*28 days*	*7 days*	*28 days*
Great Britain	300	375	..	..	..
U.S.A..	..	275	..	..	..
France.	..	143	213	1,425	2,490
Germany	..	256	356	2,560	3,910
Belgium	256	312	384	4,266	5,690

Strength tests made with a perfectly clean sand of scientifically controlled grading and definite (and usually small) proportion of water serve the purpose of comparing the qualities of different cements and of eliminating inferior cements, but such tests do not truly reveal the concrete-making qualities of cement. In practical work, the proportion of sand and aggregate to cement is about 6 to 1 instead of the 3 to 1 of the standard tests, and the proportion of water to cement is about double that of the standard tests. As an attempt to apply tests to cement which will correspond to practical conditions, the methods of testing described in the Code of Practice for Reinforced Concrete [7, 1934] may be used. In this procedure, proportions up to 2 parts sand and 4 parts coarse aggregate per part of cement are provided for, and with such a mixture the ratio of water to cement must be at least 0·6. A minimum compression strength at 28 days of 3,375 lb. per sq. in. is specified for this mixture.

No British standard specification for rapid-hardening Portland cement has yet been published, but such cement usually develops at an age of 24 hours the same tensile strength as ordinary Portland cement does at 7 days. The American and continental specifications for rapid-hardening cement require tensile strengths of about 350 lb. per sq. in. at 3 days and 450 lb. at 7 days.

There is no British standard specification for aluminous cement, but at 24 hours the mortar tensile strength (3 parts standard sand, 1 part cement) usually exceeds 500 lb. per sq. in., and the concrete strength (Code of Practice) at the same age exceeds 5,000 lb. per sq. in.

The discrepancy between laboratory tests for strength and the strength of concrete attained in practice—field test—has already been referred to and the importance of the water/cement ratio explained. There is also another factor of importance in this connexion, viz. the cleanliness of the sand and gravel or stone mixed with the cement. If the large pieces of aggregate are coated with clay, the adhesion of cement mortar is hindered, or if the sand contains more than 2 or 3% of loam or clay the setting and hardening of cement are interfered with and a weak concrete results. Especially objectionable is the presence of organic vegetable compounds frequently found in pit sands, and it is usual to apply a colorimetric test with caustic soda to sands suspected of containing such material.

Chemical and Physical Changes during Setting and Hardening of Cement

When **Portland cement** is mixed with water and in the course of time sets and hardens, both hydrolysis and hydration occur. The reactions taking place during these processes have long been the subject of investigation and controversy, but recent work has indicated that the probable changes are represented by the following equations:

(1) $3CaO \cdot SiO_2 + xH_2O = \underset{\text{amorphous}}{2CaO \cdot SiO_2 \cdot xH_2O} + \underset{\text{crystalline}}{Ca(OH)_2}$

(2) $2CaO \cdot SiO_2 + xH_2O = \underset{\text{amorphous}}{2CaO \cdot SiO_2 \cdot xH_2O}$

(3) $3CaO \cdot Al_2O_3 + 6H_2O = \underset{\text{crystalline}}{3CaO \cdot Al_2O_3 \cdot 6H_2O}$

(4) $4CaO \cdot Al_2O_3Fe_2O_3 + xH_2O = 3CaO \cdot Al_2O_3 \cdot 6H_2O + \underset{\text{amorphous}}{CaO \cdot Fe_2O_3 \cdot xH_2O}$

These reactions proceed slowly in a mass of set cement because time is required for the penetration of water to the centre of some of the coarser particles of cement, and also the action of water is impeded by the formation of gel which coats the particles, so that the hydration of the interior of the particles can only proceed by abstraction of water from such gel. It has been proved [4] that in a set cement 2 years old, the reaction shown in equation (1) above was still about 20% short of completion. For this reason, a set cement if ground to a fine powder and mixed with water still develops a proportion of its original strength. Naturally, the finer a cement is ground, the greater is the amount of early reaction with water and the more quickly is the strength developed. This behaviour has been taken advantage of by manufacturers and has been the basis of the great quality improvement that has taken place in cement during the last 30 years. At the beginning of this century it was common for cements to leave a residue of 5% on a sieve of 50 meshes per linear inch, whereas modern cements usually leave no more than 5% residue on a sieve of 170 meshes per linear inch. The modern cements possess at early dates more than double the strength of the older coarse cements. Rapid-hardening Portland cements owe much of their special properties to extreme fineness of grinding. Dicalcium silicate is naturally very slow to hydrate even when finely divided, and after 2 years still shows a large amount of unhydrated material.

Strength tests of the pure compounds which go to make cement show that tricalcium silicate is the all-important constituent at early dates. Up to a period of 28 days after mixing with water, dicalcium silicate has very little cementitious value, but at 3 months its strength is equal to that developed by tricalcium silicate at the same age, and at 2 years it has a strength higher than any of the other constituents of Portland cement. It has been difficult to determine the strength influence of tricalcium aluminate because in the pure state it sets immediately on coming into contact with water. It is, however, well established in practical

manufacture that, other things being equal, a Portland cement with high alumina content has greater strength at 1 or 2 days than a high silica cement.

It is evident that the main strength development of Portland cement is brought about by the formation of colloidal hydrated dicalcium silicate. The hypothesis has been put forward that a particle of cement on being wetted acquires a layer of this colloid compound which is not freely permeable to water. The unhydrated interior of the grain then absorbs water for its hydration from this layer, and the latter becomes desiccated and acquires greater rigidity and strength. The hydration of the interior leads to the formation of more gel, which in its turn contributes to strength. In accordance with this hypothesis, tricalcium silicate is of great importance because it commences to hydrolyse to a colloid almost immediately, in distinction to dicalcium silicate which appears to require nearly a month's contact with water before commencing to hydrate.

Tricalcium aluminate hydrates very rapidly to the extent of 75% in one day, and almost completely in a month; although its rapid setting has prevented strength tests of the pure compound being made, the commercial value of tricalcium aluminate, already referred to, has led to the suggestion that its crystalline hydration product provides a rigid skeleton upon which the silicate gels can build.

The incorporation of a small proportion (2 to 5%) of gypsum—hydrated calcium sulphate—with cement is necessary to retard the setting to a reasonable period. It has been established that the function of gypsum is to combine with tricalcium aluminate as it dissolves to form calcium sulphoaluminate ($3CaO \cdot Al_2O_3 \cdot 3CaSO_4 31H_2O$). The delayed development thus caused, of crystalline hydrated tricalcium aluminate, leads to retardation of the setting of the cement.

The strengths of neat cement pastes and of cement mortars and concretes are affected enormously by the proportion of water to cement present—commonly known as the water/cement ratio. With neat cement at least 20% of its weight of water is needed to make a paste, and with concretes the water/cement ratio ranges from 0·6 to 1·0 and even more in order to produce a mixture that will have the necessary fluidity for practical construction. The amount of water required for hydration and hydrolysis of cement is no more than 12% of the weight of cement at early dates, and thus it can be realized that the large excess of water above this figure that is incorporated in concrete is a source of weakness. Cement concrete is in fact a mass of sand and stones with the voids filled with cement paste and water, or if the concrete is dried, with cement paste and air.

By reducing the proportion of water (or air) voids the strength of the concrete can be increased, provided the concrete is sufficiently consolidated. Laboratory tests of concrete made with the minimum percentage of water for consolidation frequently show double the strength of field concrete in which the water/cement ratio may be double (or even greater) that used in the laboratory.

As already indicated, the processes of hydration and hydrolysis of the constituents of Portland cement are slow and progressive, thus necessitating the presence of water for development of strength. The amount of water that cement has absorbed in chemical combination at an age of 1 month is practically double the amount similarly combined at an age of 1 day, and unless this additional water is available the cement will not develop its normal strength. This is the reason for the necessity of so-called 'curing' of concrete, i.e. the provision of water needed for hydration and hydrolysis, either by covering to prevent excessive evaporation or by frequent addition of water to keep the set concrete moist.

When **aluminous cement** sets and hardens the reactions proceed much more rapidly than in the case of Portland cement, and the principal result [3, 1925] is the formation of a hydrated dicalcium aluminate ($2CaO \cdot Al_2O_3 \cdot 7H_2O$) with liberation of some alumina. Owing to the speed of the hydration process, considerable heat is developed in the mortar or concrete during the first day after mixing, and special precautions are needed to prevent evaporation of water. The rapidity of the chemical changes connotes that strength is developed quickly, and this is one of the characteristic properties of aluminous cement.

Setting Time of Cement

This is the term used for defining the periods taken by a cement-water paste to reach certain stages of rigidity. The conventional terms 'initial set' and 'final set' have in fact no direct connexion with the commencement and end of setting, because the process of setting begins as soon as cement and water are mixed, and there is no definable end of setting, because setting merges into hardening without any known boundaries between the two stages. So-called 'initial set' is the time taken for a cement paste to stiffen to such an extent that a needle 1 mm. square weighted to 300 g. cannot completely penetrate a block 40 mm. thick. 'Final set' is said to occur when the needle fails to penetrate to a depth of 0·5 mm. This is known as the Vicat test, and is almost universally used.

The value of the setting-time test is that it informs the user of cement what period (i.e. initial setting time) elapses after mixing before the cement becomes too stiff to be a plastic workable mass. The final set should not occur too long after the initial set, because in this intermediate condition concrete is more likely to be damaged by frost and heavy rain.

The British standard specification for Portland cement requires the initial setting time to be at least 30 minutes, and the final setting time not more than 10 hours. Ordinary cement usually has an initial setting time of 1 to 3 hours and a final setting time of 2 to 5 hours. Aluminous cement usually has a longer initial set averaging 4 to 5 hours, but the final set takes place only an hour or two later.

The setting time of cement is affected by temperature conditions; below 40° F. setting proceeds very slowly and cement paste will remain soft for many hours. Above 80° F. there is considerable acceleration of setting, and at 100° F. initial set may occur within a few minutes of mixing. In practice, it is recommended that in conditions of low temperatures, the aggregates and water to be used in concrete should be heated and the concrete kept well protected to prevent its temperature falling below 40° F. The evolution of heat that takes place a few hours after mixing cement and water is of great assistance in maintaining the temperature of concrete subjected to low temperature conditions.

Soundness or Stability. By the soundness of cement is meant freedom from tendencies to disintegration or expansion. This quality can be tested for by observing whether warping or cracking of thin cakes of set cement stored in air or in water occurs during a period of 28 days. Accelerated tests are, however, more frequently employed, in which the thin cakes of cement are immersed in boiling water or kept in an atmosphere of steam for a few hours, and the same freedom from warping or cracking is insisted upon to ensure a good cement. As a quantitative test for soundness

the Le Chatelier test is employed, in which a small split cylindrical mould is filled with cement paste, and after the latter is set, immersed in boiling water for 3 hours. Any expansion of the cement opens the split mould, and the degree of expansion is measured by the distances between the ends of pointers soldered to the split sides of the mould.

Unsoundness in cement is caused by the presence of uncombined lime which has not become hydrated until after the cement has hardened; the increase of volume due to the conversion of CaO to CaH_2O_2 causes the cement mortar or concrete to expand, and this may lead to cracking or disintegration. This hydration of the lime may not occur for several weeks after the cement has set, owing to the slow penetration of water through coarse particles of cement, and the accelerated boiling water and steam tests are designed to expedite this hydration and so reveal within 2 days any expansive effect which would not occur at ordinary temperatures for several weeks. A more stringent test involving the use of an autoclave to obtain a temperature above the normal boiling-point of water is sometimes applied to cements intended for use in grouting deep oil-wells, because in such conditions the temperature and pressure are above those occurring under atmospheric conditions.

The free lime which is the cause of unsoundness in cement is in essence the result of imperfections in the process of manufacture. Such free lime may be the result of an excessive proportion of lime in the cement, i.e. beyond that needed to combine with silica, alumina, and iron oxide; or it may be due to coarse grinding of the raw material mixture preventing combination taking place during the burning process, or it may arise from the temperature of burning being too low to effect the complete combination of lime and silica. Up to 2% of free lime in Portland cement is usually considered acceptable and does not affect the stability of the cement.

Expansion and Contraction. Hardened cement has the property of expanding when moistened and of contracting when dried. This behaviour is probably an essential accompaniment of the gel structure of set cement.

Investigations [1, 1928, &c.] have shown that at an age of 20 days the shrinkage movement of concrete in air per unit length is about 20×10^{-6}, increasing to a maximum of 370×10^{-6} at 18 months. When concrete is stored in water the expansion reaches its maximum at about 30 days, and is then only about 3×10^{-6} of unit length. These so-called moisture movements, as might be expected, have an important bearing on concrete construction, and long stretches of concrete walls and roads are liable to crack through shrinkage. To make provision for this it is customary to introduce joints in the concrete at intervals of 30 ft. or more. In roads these joints are filled with plastic—usually bituminous—material. In the case of walls, dams, and similar long stretches of concrete, specially designed joints are used to allow of the concrete on each side advancing or receding without breaking the continuity of the construction. In a concrete structure reinforced with steel, the shrinkage of the concrete causes a compression stress to be set up in the steel, and due provision is made for this in the design.

In addition to moisture movement of concrete, there is the normal behaviour of expansion with rise in temperature and contraction on cooling, the linear coefficient or expansion being $1{\cdot}206\times10^{-5}$ per °C. The fact that this coefficient is so close to that of steel renders possible the use of steel in concrete as reinforcement.

Thermal Characteristics of Cements

During the setting and hardening of Portland, aluminous, and other similar cements, heat is evolved as the result of chemical action. This heat evolution may have beneficial or adverse effects according to the conditions in which the cement is used. In small constructional members the higher temperature of the concrete produced by the development of heat expedites the hardening and is beneficial. In such cases the loss of heat by radiation is considerable, so that the temperature does not rise to a degree that is detrimental. In large masses of concrete such as dams, the loss of heat by radiation is very gradual, and consequently the temperature of the interior of the mass may rise by as much as 40° C. [9, 1934]. The subsequent cooling leads to shrinkage which may cause cracking of the concrete, the tendency to which is accentuated by the fact that the exterior of the concrete cools rapidly while the interior is still hot. A Portland cement/water paste when kept under well-insulated conditions such as in a Dewar flask will rise to boiling-point in a few hours, but the heat evolution continues almost indefinitely for a very long period—naturally as long as chemical action continues—although the quantity of heat developed after a few days is immeasurable except under strictly adiabatic conditions. The subject of heat development by setting and hardening cement has been closely investigated during the past few years in connexion with some large concrete dams being erected in the U.S.A., and specifications have been drawn up for special cements with low heat development. Naturally, development of heat proceeds with development of strength, and therefore the so-called 'low-heat cements' do not excel in strength. The chief strength-contributing constituents of Portland cement at early dates are tricalcium silicate and tricalcium aluminate, and as the following table [5] shows these have the highest heat evolution on hydration.

	Heat evolved on complete hydration
Tricalcium aluminate	207 calories per gramme
Tricalcium silicate	120 „ „ „
Dicalcium silicate	62 „ „ „
Tetracalcium alumino-ferrite	100 „ „ „

The cement specification for the Boulder Dam in the U.S.A. requires that the heat of hydration shall not exceed 65 calories per gramme of cement at an age of 7 days or 75 calories per gramme at 28 days. Normal Portland cements show a heat evolution of about 85 calories per gramme at 7 days and 90 calories per gramme at 28 days.

For the Norris and Wheeler Dams (U.S.A.) the heat evolution is controlled by the following stipulations as to chemical constitution of the cement:

Tricalcium silicate ($3CaO{\cdot}SiO_2$)—not more than 35%.
Dicalcium silicate ($2CaO{\cdot}SiO_2$) „ „ „ 60%.
Tricalcium aluminate ($3CaO{\cdot}Al_2O_3$) not more than 7%.
Tetracalcium alumino-ferrite ($4CaO{\cdot}Al_2O_3{\cdot}Fe_2O_3$)—not more than 20%.

The heat evolved by different types of cement is as follows:

	Heat evolved in g. cal. per g. after		
	1 day	*2 days*	*3 days*
Portland cement	23–42	42–65	47–75
Rapid-hardening Portland cement	35–71	45–89	51–94
Aluminous cement	77–93	78–94	78–95

Comparatively small concrete members made with aluminous cement may attain temperatures approaching the boiling-point of water. For this reason aluminous cement concrete should be kept moist during the setting process. Pozzolana cement has some claims to be a 'low-heat cement', because its content of Portland cement is only about 60%, and although the pozzolanic action (combination of lime with silica) also contributes heat, this action is slow and usually less than the heat loss by radiation.

Resistance of Cements to Corrosion

It will be obvious that cements which are essentially calcareous can have little resistance to acid attack, and this implies that cement concrete in contact with acids or with materials likely to develop acid properties is liable to corrosion. Animal and vegetable fats, beer, cider, milk are examples of materials which may develop an acid reaction. In addition, sugars have a disintegrating effect on cement, owing to the solubility of lime in sugar solution. When a dense concrete is made by using suitable proportions of cement and water with properly graded sand and aggregate, the corrosive action of acids is confined to the surface, and with weak organic acids the rate of disintegration is slow. But where the acid liquid can penetrate the concrete, the life of the latter is necessarily short. This vulnerability to acid attack does not limit the use of concrete for constructional purposes, but merely calls for some surface protection, of which asphalt is a popular example.

Portland cements are also subject to chemical attack by sulphate solutions such as occur in sea-water and in certain soils. The mechanism of the action is that tricalcium aluminate present in cement combines with calcium sulphate to form calcium sulpho-aluminate ($3CaO \cdot Al_2O_3 \cdot 3CaSO_4 \cdot 31H_2O$) with an increase in volume sufficient to disintegrate concrete. The calcium sulphate for this reaction need not be originally present, but may be formed by interaction of lime (always present in set cement) and any soluble sulphate. The rate of destructive action by sulphate solutions is dependent on the strength of the latter and the permeability of the concrete. A dense concrete immersed in sea-water which contains from 0·2 to 0·5% SO_3 has an almost indefinite life, but a permeable concrete in sea-water may show signs of attack in a few years. In soils which may contain stronger solutions of magnesium or sodium sulphates, the disintegrating action is more rapid. The protection of the concrete surface by an asphaltic or other bituminous cover is a remedy for sulphate attack, but aluminous and pozzolana cements are less liable to attack and may be preferable under certain circumstances. Aluminous cement does not liberate lime on setting, and there are consequently not the conditions required to form the expansive calcium sulpho-aluminate. With pozzolana cement the lime set free during setting of the Portland cement constituent combines with the active silica of the pozzolana, and is thus not available for the formation of calcium sulphate.

Cement mortars and concretes are also liable to attack by certain moorland waters and other waters containing free carbonic acid. In the case of moorland water the action is one of simple solution of the hydrate of lime in the set cement. With a dense concrete or mortar the attack is superficial only, and years may elapse before there is any noticeable effect. If the concrete is permeable, as may happen with a dam which has cracked by shrinkage, considerably more lime can be removed from the cement by solution. There are many natural waters which contain bicarbonate of lime in solution, and these have a protective action on concrete, because interaction with the free lime in the latter forms a skin of carbonate of lime. There are, however, some natural waters containing free carbonic acid which causes removal of lime by solution as bicarbonate of lime. In both these cases of pure moorland water and of water containing free carbonic acid, the remedy is to be found in the use of aluminous or pozzolana cement where there is little or no lime hydrate available for attack.

Oil-well Cements

For sealing comparatively shallow wells, say up to 2,000 ft. deep, a slow setting, ordinary Portland cement is found to be satisfactory.

For deep oil-wells special cements have to be used on account of the high temperatures occurring at greater depths, which cause quick setting in ordinary Portland cements.

There is no universally accepted specification for oil-well cements, but tentative specifications have been put forward, and oil companies have their own specifications. In these the tests are carried out at temperatures ranging from atmospheric to 194° F. These specifications are suitable for wells up to about 7,000 ft. deep, but manufacturers are now endeavouring to make cements suitable for the higher temperatures found at greater depths.

The chief items in the specifications for oil-well cements are: (1) slow setting, (2) high strength after setting, and (3) resistance to the action of sulphate and chloride waters.

The 'initial setting time' as determined by the Vicat or Gilmore needles is used, but at this stage in the setting the grout has become too stiff for pumping. In practice, the limit of setting is reached when the cement grout has stiffened to an extent which prevents the pumps from driving the grout to the back of the casing. Pressures up to 1,400 lb. per sq. in. have sometimes to be used.

The degree of stiffening or gelling can be determined by a special stirring device, in which the resistance to rotation of a paddle is transmitted to a pressure gauge, which gives a measure of the gelling effect and an indication of the extra pump pressure required to counteract it. A test of this kind would be more useful than the needle test, but existing specifications include only the needle test. In Reid's specification [6, 1935], where the water/cement ratio is taken as 0·40 and the temperature as 100° F., the limits of the initial set are given as not less than 2½ hours and not more than 3½ hours, the final set not more than 4½ hours and as close to the initial as possible. In another specification with water/cement ratios of 0·40 and 0·60 the maximum initial set is given as 1 and 1½ hours respectively, at a temperature of 194° F. Another specification suggests 2 hours initial set at 140° F., and adds that this should give 1½ hours before the grout becomes unpumpable, which is the minimum time required by the operators to mix and place it behind the casing.

It is important that the grout when placed behind the casing shall attain high early strength. Reid's specification [6, 1935] requires 350 lb. per sq. in. tensile strength at 100° F. with water/cement ratio 0·40, while another requires 142 lb. per sq. in. at 194° F. with water/cement ratio 0·40, and 71 lb. per sq. in. at 194° F. with water/cement ratio 0·60, all at 3 days.

The gelling effect can be delayed by increasing the water/cement ratio, but this has two disadvantages. All

cements have a tendency to settle out of grouts, leaving water on the top, and the greater the water/cement ratio the greater will be the settlement. In the well, such settlement causes water spaces behind the casing and prevents good sealing. Then the strength of the set grout falls very rapidly as the water/cement ratio is increased, as is indicated in one of the specifications quoted above, where the strength required at water/cement ratio 0·60 is only half of that at water/cement ratio 0·40.

The types of cement recommended are special Portland cements, aluminous cements, slag cements, Pozzolanic cements, and Portland cements with various additions.

In the case of special Portland cements the chief active constituents are given as:

(1) Tricalcium silicate, $3CaO \cdot SiO_2$.
(2) Dicalcium silicate, $2CaO \cdot SiO_2$.
(3) Tricalcium aluminate, $3CaO \cdot Al_2O_3$.

The tricalcium silicate and the tricalcium aluminate are responsible for rapid hardening and high early strength in cement, while dicalcium silicate shows little strength at early dates at normal temperatures and high strengths at later periods.

Manufacturers of cement make use of this knowledge, and some oil-well cements have little or no tricalcium aluminate; others have low proportions of both tricalcium aluminate and tricalcium silicate, while the proportion of dicalcium silicate is relatively high.

There are other factors in the manufacture apart from chemical constitution. The proportion of gypsum is usually as high as the specification permits, since this tends to give a slow set and rapid early strength. The degree of burning and grinding of the clinker have marked effects on the initial setting time, the viscosity of the grout, and the amount of settlement of the cement in the grout.

Aluminous cement has the properties of very slow setting and great hardness at early dates, and resists well the action of sulphate and chloride waters.

Pozzolanic cement should, theoretically, be the ideal cement for oil-wells, as it can be made slow setting and has the property of acquiring great strength at high temperatures, and is highly resistant to sulphate waters.

Bentonite as an addition to Portland cement grout to reduce resistance to pumping has been suggested, while the addition of fibrous material [2] such as asbestos [8, 1929] has been stated to prevent leakage of the grout into porous formations.

Calcium chloride solution is sometimes added to the last batch for the purpose of forming the plug, as it quickens the setting, but for deep wells this is not necessary as the difficulty is to avoid quick setting.

A considerable amount of experimental work has already been done in order to obtain a suitable cement for sealing oil-wells, and is still in progress, but the further deepening of wells has altered the original requirements so that now further research is needed.

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CASING

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PRACTICALLY all the serious problems in drilling and producing operations result from the necessity of searching for petroleum at continually increasing depths. Probably no one of these problems is of more critical importance than the selection of casing that will ensure the successful completion and subsequent production of a well. In numerous instances recently, due to the exigency of the conditions, casing has been set at depths where the factors of safety against failure by collapse and pull-out were reduced to a dangerously narrow margin. That these strings have been set without mishap is a tribute both to the excellent engineering supervision of the operators and the uniformly high quality of casing that is now available. It is generally appreciated that too great reliance cannot be placed on the continuance of this success in wells of great depth, and consequently there is a concerted effort to improve both the design of the joint and the strength of the steels. Some of these developments have already been reduced to practice and are being utilized with both efficiency and economy.

Materials and Methods of Manufacture.

Prior to the advent of seamless pipe, choice of casing was limited to two types, lap-welded wrought iron and lap-welded steel pipe. For many years the application of lap-welded steel casing has been correctly restricted to shallow, low-pressure fields and surface-conductor pipe. It provides but slight advantage in the way of increased strength over the more expensive lap-welded wrought-iron casing, which is also restricted to use in shallow, low-pressure fields because of the limitations imposed by its low physical properties. The continued use of lap-welded wrought-iron casing may be attributed to the belief of the users that it provides greater resistance to corrosion. With ample justification, this is considered to be a debatable fact by many operating engineers; no other reason exists for recommending its use. Recent improvement in manufacturing methods has made it feasible to produce alloy wrought-iron pipe and it is now possible to procure lap-welded wrought-iron casing containing up to 1·5% of nickel. The alloy addition increases the physical properties and probably adds somewhat to the corrosion resistance.

Two developments in recent years, higher strength lap-welded steel pipe and electrically welded steel pipe, have reduced to some extent the virtual monopoly of seamless-steel casing which had persisted for many years. Economic conditions in the oil industry have been favourable to these developments, since both types are less expensive than seamless-steel pipe. However, seamless-steel casing will continue to be the standard type because it has proved itself to be fully capable of satisfactory performance under the most rigorous conditions and manufacturing methods permit the greatest possible flexibility in the choice of materials.

Typical chemical analyses and physical properties of the various casing materials are given in Tables I and II respectively.

From Table I it is apparent that the high-strength lap-welded steel pipe differs from the regular lap-welded pipe in only one important respect, carbon content. The higher strength, evident from Table II, is due solely to this difference. The successful application of the higher carbon steel to the fabrication of lap-welded casing is not a matter merely of substitution of one grade of steel for another; it requires a special welding technique perfected only after systematic development. Distinctly worth while economy is possible to the operator who uses this type of casing where it is suitable. The sole hazard involved is the failure to detect defective welds before the casing is set. The advantages are: lower first cost and strength that is slightly less than that of Grade C seamless casing of equal weight. The difference in cost is great enough so that frequently a saving can be effected by the substitution of heavier high-strength lap-welded casing for the Grade C seamless casing that would otherwise be used. This is a distinct advantage in corrosive fields since the rate of corrosion of all casing materials is essentially the same and the life of casing under such conditions is determined by the wall thickness.

Two types of electric-welded casing, both cheaper than seamless casing, are available. The two processes by which they are made are similar in most of the essential details: flat, pickled plates, sheared to exact width, are cold-formed into circular or oval shapes, the edges of which are fused together by resistance-electric welding. The weld-finishing and sizing

TABLE I

Chemical Composition of Casing Materials

Material and type	*API. grade*	*Constituents* (%)* Carbon	Manganese	Silicon	Other elements
Lap-welded wrought iron	wrought iron	0·020	0·040	0·110	..
Lap-welded alloy wrought iron	.	0·020	0·040	0·100	nickel 1·500
Lap-welded steel	O.H. Class 1	0·120	0·580	0·010	..
Lap-welded, high-strength steel	..	0·230	0·650	0·020	..
Seamless steel	Grade C	0·410	0·770	0·180	..
Electric-welded steel	,,	1·230	1·190	0·030	..
Seamless steel	Grade D	0·440	1·360	0 190	..
,, ,,	,,	0·400	1·100	0·250	chromium 0·180
Electric-welded steel	,,	0·370	1·400	0·010	..
,, ,, ,,	,,	0·310	1·350	0·042	..
Seamless steel	Grade E	0·400	1·100	0·850	chromium 0·500

Phosphorus and sulphur 0·04 maximum except for wrought iron.

operations differ in detail, but the product in each case is scale-free, longitudinally welded casing. One product is available in all sizes of two grades which comply with the American Petroleum Institute Pipe Specifications for Grade C and Grade D casing respectively. The other product is available, at the present time, only in sizes of 6⅝ in. and larger Grade D casing. The points of superiority claimed for each are: high ration of yield strength to ultimate strength, greater uniformity in size and wall thickness and a scale-free surface both inside and outside.

In the casing available in two grades the higher ratio of yield strength to ultimate strength results from the cold-

TABLE II

Physical Properties of Casing Materials

Material and Type	*API. grade*	*Yield-point (lb. per sq. in.)*	*Tensile strength (lb. per sq. in.)*	*Elongation (% in 2 in.)*	*Reduction of area (%)*	*Brinell hardness*	*Impact strength (ft.-lb.)*
Lap-welded wrought iron	wrought iron	28,000	46,000	16·5*	..	..	..
Lap-welded steel	O.H. Class 1	31,800	55,600	42·5	59·3	115	..
Lap-welded, high-strength steel	..	40,800	75,900	23·5*		140	..
Seamless steel	Grade C	57,500	90,500	29·5	48·9		20·0†
Electric-welded steel	,,	61,400	76,700	37·0	50·7	173	..
Seamless steel	Grade D	70,500	107,000	31·0	47·0	..	39·0†
,, ,,	,,	64,700	107,500	25·0	43·0	..	..
Electric-welded steel	,,	67,200	102,100	35·0	51·0	201	..
,, ,, ,,	,,	100,800	107,900	28·8	..	..	39·1‡
Seamless steel	Grade E	75,000	122,500	21·5	40·0	263	..

* Elongation in 8 in. † Izod impact test. ‡ Charpy impact test.

TABLE III

Comparison of Setting Depths for Lap-welded, High-strength Lap-welded, Electric-welded and Seamless Grade C Casing*

		Setting depth (ft.)					
		Collapse† (safety factor 2)			*Tension (safety factor = 2½)*		
		Lap-welded			*Lap-welded*		
Size	*Weight per ft. (threads and coupling)*	*Regular*	*High strength*	*Seamless and electric-welded Grade C*	*Regular*	*High strength*	*Seamless and electric-welded Grade C*
4½	16·00	4,708	5,650	6,497	3,915	4,894	6,174
5½	14·00	2,081	2,497	2,872	3,674	4,593	5,794
	17·00	2,834	3,401	3,912	3,650	4,563	5,756
	19·50	3,588	4,306	4,952	3,716	4,645	5,860
	22·50	4,342	5,210	5,992	3,674	4,593	5,794
6⅝	20·00	2,382	2,978	3,287	3,697	4,621	5,642
	24·00	3,219	4,024	4,442	3,727	4,659	5,688
	26·00	3,651	4,564	5,038	3,744	4,679	5,713
	28·00	4,069	5,086	5,616	3,746	4,682	5,716
7	20·00	1,982	2,478	2,735	3,647	4,559	5,563
	22·00	2,341	2,926	3,230	3,653	4,567	5,572
	24·00	2,725	3,406	3,760	3,677	4,596	5,608
	26·00	3,096	3,870	4,273	3,684	4,605	5,619
	28·00	3,480	4,350	4,802	3,696	4,621	5,638
	30·00	3,581	4,814	5,315	3,697	4,621	5,638
7⅝	26·40	2,342	2,928	3,232	3,555	4,443	5,418
	29·70	2,876	3,595	3,970	3,589	4,486	5,471
	33·70	3,502	4,378	4,832	3,599	4,499	5,487
8⅝	28·00	2,027	2,534	2,798	3,381	4,226	5,239
	32·00	2,561	3,201	3,534	3,398	4,248	5,267
	35·50	3,094	3,868	4,270	3,455	4,319	5,354
	39·50	3,628	4,535	5,006	3,452	4,315	5,350
10¾	40·50	1,436	1,723	1,981	3,054	3,665	4,631
	45·50	1,839	2,207	2,538	3,092	3,710	4,688
	51·00	2,242	2,690	3,094	3,088	3,706	4,682
	55·50	2,605	3,126	3,595	3,108	3,730	4,712
13⅜	48·00	752	902	1,038	2,637	3,164	4,066
	54·50	1,076	1,291	1,485	2,664	3,197	4,108
	61·00	1,400	1,680	1,933	2,683	3,220	4,137
	68·00	1,724	2,069	2,380	2,677	3,212	4,127

* From data published by casing manufacturers † Collapse setting depths calculated for salt water.

forming operations prior to welding. In the other product this ratio is still further increased by compressing the welded pipe in a die-press so that an average reduction of about 6% in the diameter is accomplished. The high yield strength is necessarily accompanied by a reduction in ductility and toughness of the steel, but this is probably not serious since, in both types, the residual ductility still exceeds the minimum requirement for casing.

It should not be overlooked that comparably high ratios of yield strength to ultimate strength are readily attainable in seamless casing by only slight modification of the regular finishing operations.

Because of the high temperature reached by the metal and the positive pressure control, the electric-welded casing introduces less hazard from defective welds than lap-welded casing. Both types are, however, subject at least to the suspicion of being susceptible to accelerated localized corrosion in the vicinity of the weld. While it is true that the welding is accomplished with a minimum of disturbance of the internal structure it can be readily demonstrated, as is evident from Fig. 1, that structural inhomogeneity exists in the vicinity of the weld. Metal that is not uniform internally with respect either to structure or stress often suffers local accelerated attack. A normalizing treatment after welding would remove this possibility, but in the one type of casing it would also restore the normal relationship between yield strength and ultimate strength. This relation would not be altered for the other type of casing if the normalizing treatment preceded the compressing operation.

TABLE IV

Comparison of Setting Depths, for Electric-welded, Seamless and High Yield Electric-welded, Grade D Casing*

Size	Weight per ft (threads and coupling)	Setting depth (ft.): Collapse† (safety factor = 2): Seamless and electric-welded	High yield electric-welded	Tension (safety factor = 2¼): Seamless and electric-welded	High‡ Yield electric-welded
4½	16·00	8,216	..	7,663	..
5½	14·00	3,631	..	7,179	..
	17·00	4,946	..	7,133	..
	19·50	6,261	..	7,262	..
	22·50	7,576	..	7,180	..
6⅝	20·00	4,156	4,980	6,984	8,000
	24·00	5,617	6,920	7,041	8,000
	26·00	6,370	7,780	7,071	8,000
	28·00	7,101	8,580	7,076	8,000
7	20·00	3,458	3,750	6,882	8,000
	22·00	4,085	4,890	6,893	8,000
	24·00	4,754	5,810	6,937	8,000
	26·00	5,403	6,660	6,951	8,000
	28·00	6,072	7,440	6,975	8,000
	30·00	6,721	8,180	6,975	8,000
7⅝	26·40	4,087	4,880	6,699	7,760
	29·70	5,019	6,185	6,746	7,760
	33·70	6,110	7,480	6,784	7,760
8⅝	28·00	3,538	..	6,473	..
	32·00	4,469	..	6,507	..
	35·50	5,399	..	6,615	..
	39·50	6,330	..	6,610	..
10¾	40·50	2,505	2,205	5,811	6,400
	45·50	3,209	3,270	5,883	6,400
	51·00	3,912	4,580	5,876	6,400
	55·50	4,545	5,530	5,913	6,400
13⅜	48·00	1,313	965	5,088	5,200
	54·50	1,878	1,455	5,141	5,200
	61·00	2,444	2,150	5,177	5,200
	68·00	3,009	2,990	5,164	5,200

* From data published by casing manufacturers.
† Collapse setting depths calculated for salt water.
‡ Minimum values which may be subject to revision upward.

Table III provides a comparison of setting depths for lap-welded, high-strength lap-welded, and Grade C seamless and electric-welded casing. A similar comparison is given in Table IV for Grade D seamless and electric welded and high yield, electric-welded casing. The setting depths represent data published by casing manufacturers, and those in Table IV particularly should be considered after a study of the section on collapsing strength.

Collapsing Strength.

Collapsing strength is the most important factor to be considered in setting a long string of casing since it may eventually have to withstand external pressure equivalent to that of a hydrostatic head as great as the depth of the well. The theoretical calculation of the collapsing strength of commercial casing is rendered extremely impracticable because of the numerous variables involved. The setting depth data published by manufacturers of casing are derived, with one exception, from calculations by empirical formulae developed by Stewart [10, 1906] in an investigation of the collapsing strength of lap-welded Bessemer steel tubing. These formulae are:

$$P = 86{,}670\frac{t}{d} - 1{,}386 \qquad (1)$$

and

$$P = 50{,}210{,}000\left(\frac{t}{d}\right)^3, \qquad (2)$$

where

P = collapsing pressure (lb. per sq. in.),
d = outside diameter (in.),
t = wall thickness (in.).

Equation (1) is applicable to casing sizes where the values of t/d are greater than 0·023 and it is the equation of the average straight line of the plotted test results. For values of t/d less than 0·023 the average of the plotted test results was assumed to be a curve, tangent both to the straight line represented by equation (1) and the horizontal axis at the zero origin. Equation (2) represents this curve. The steel from which the pipe used in deriving these formulae was fabricated has an average yield-point of 37,000 lb. per sq. in. and a tensile strength of 58,000 lb. per sq. in. In order to make these data applicable to seamless casing it is customary to multiply the results given by equations (1) and (2) for lap-welded casing by the factor 1·38 for Grade C and the factor 1·745 for Grade D casing.

Later experimental work has resulted in a slight revision of Stewart's original equation (1) as follows:

for lap-welded casing $$P = 86{,}730\left(\frac{t}{d}\right) - 1{,}388 \qquad (3)$$

for seamless Grade C casing $$P = 119{,}690\left(\frac{t}{d}\right) - 1{,}915 \qquad (4)$$

for seamless Grade D casing $$P = 151{,}350\left(\frac{t}{d}\right) - 2{,}422 \qquad (5)$$

These formulae imply a tensile strength exceeding 80,000 lb. per sq. in. for Grade C material and 100,000 lb. per sq. in. for Grade D material. Actually, the average figures for commercial casing are still higher than these values thereby indicating that the minimum requirements for physical properties in the Pipe Specifications of the American Petroleum Institute should be revised upward

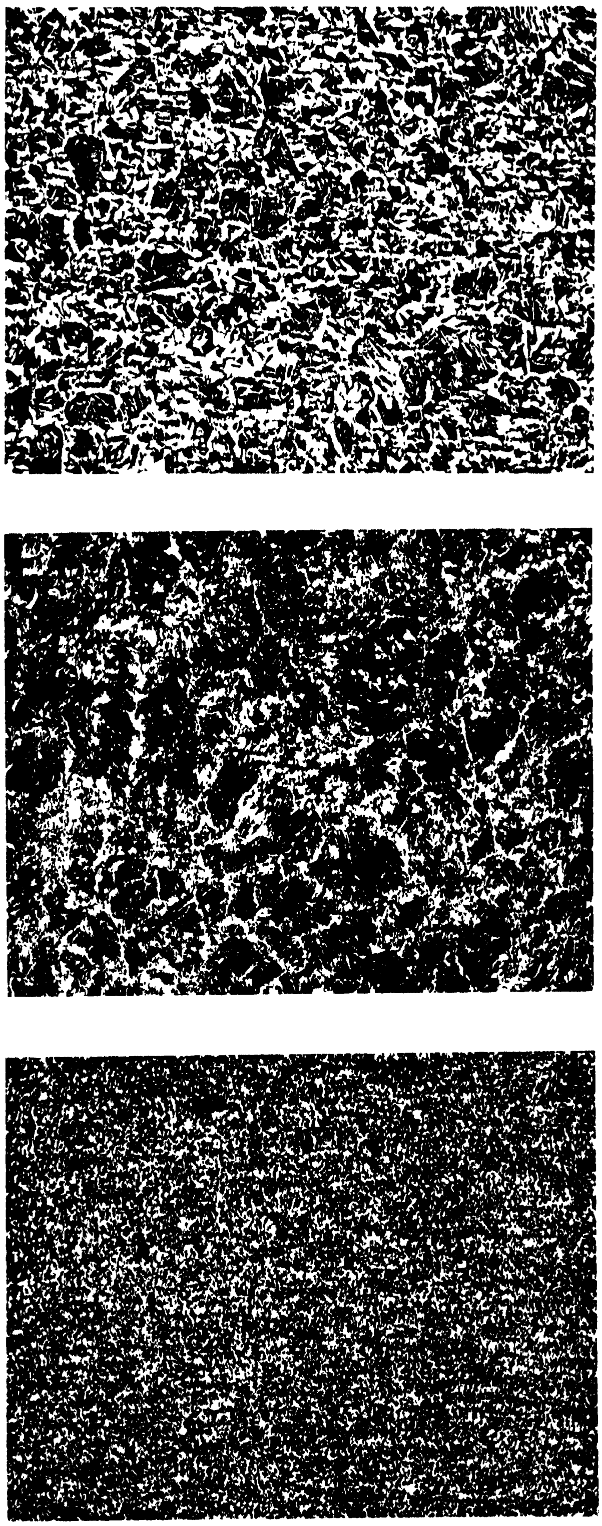

FIG. 1. Structural inhomogeneity in electric welded casing:
top—normal structure of body of casing
middle—structure at the weld
bottom—structure adjacent to weld
Magnification 100 diameters

so as to conform with present practice. The relation between collapsing strength and ratio of wall thickness to outside diameter for lap-welded, Grade C and Grade D casing based on Stewart's investigation is plotted in Fig. 2.

The maximum fibre stress on the wall of the tube at the instant of collapse varied in quite a regular manner from about 7,000 lb. per sq. in. for small values of t/d to 35,000 lb. per sq. in. for large values of t/d. This led Stewart to conclude, 'that the ability of a commercial wrought tube to withstand a fluid-collapsing pressure is not dependent alone

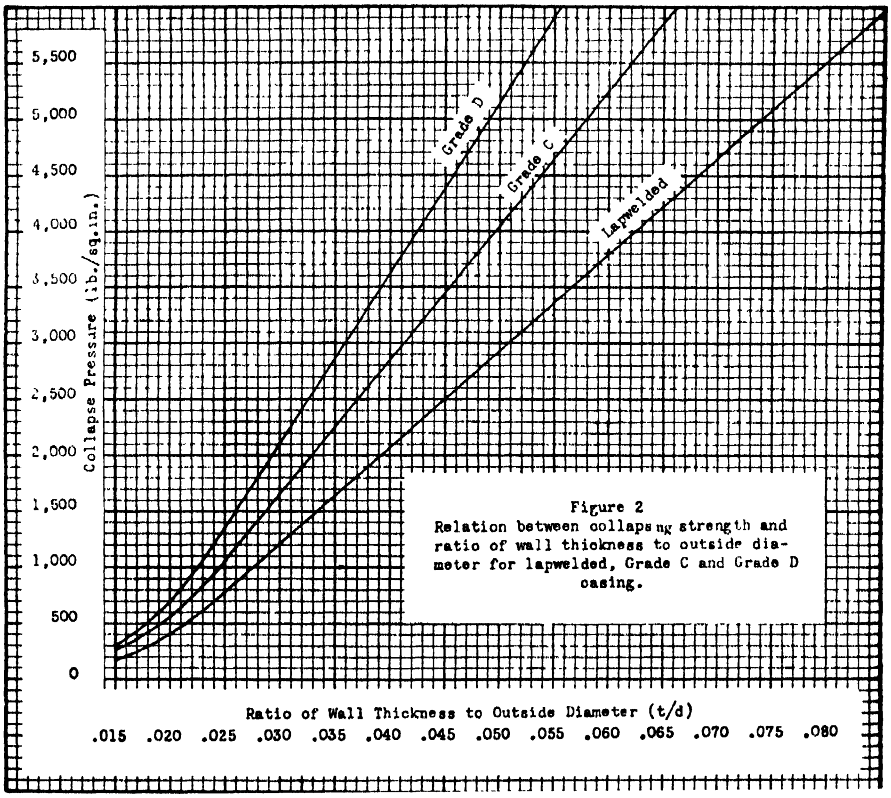

Figure 2
Relation between collapsing strength and ratio of wall thickness to outside diameter for lapwelded, Grade C and Grade D casing.

ı either the ultimate strength or elastic limit of the ɜrial constituting it'. A more recent investigation by er and Sullivan [6, 1931] considered the results of ʼart's and other previous investigations [1, 1917; 2, ı; 3, 1914; 9, 1913; 12, 1910] for the purpose of correlat- ɔbserved test data with the theory of elasticity. Of the ıtions based on this theory that developed by Sturm 1928] agreed most closely with observed data. The m equation is:

$$S = \frac{1}{3}\frac{E}{d^2/t}\left[\frac{N^4-N^2+a^4K^2+a^2K(2N^2-m)}{N^2(1-m^2)}\right], \tag{6}$$

in which,

S = stress at instant of collapse (lb. per sq. in.),
E = modulus of elasticity (30,000,000 lb. per sq. in.),
d = outside diameter of pipe (in.),
t = thickness of pipe (in.),
N = number of lobes at collapse (2 for long tubes),
a = parameter for end conditions (1 for long tubes),
$K = \frac{\pi^2}{4(l/d)^2}$,
l = length of tube (in.),
m = Poisson's ratio (0·26 for carbon steel).

Collapse of oil-well casing falls within the conditions governing the collapse of long tubes for which equation (6) can be reduced to:

$$S = \frac{2{,}680{,}000}{d^2/t}[12+K^2+7{\cdot}74K]. \tag{7}$$

When the relation between collapsing strength and the ratio of diameter to thickness (d/t) was plotted there was good agreement with the Sturm equation if the yield-point of the material was considerably above the maximum fibre stress at failure. It was also found that the Sturm equation approximately defines the collapsing strength of casing for higher d/t ratios but that as this ratio decreases the collapsing strength approaches the yield-point of the steel. From these observations Jasper and Sullivan concluded that the collapsing pressure of casing for higher values of d/t is controlled by the elastic properties of the steel and the d/t ratio, but for lower values of d/t it is controlled by the yield-point of the steel and the d/t ratio. This conclusion is at least qualitatively in agreement with Stewart's findings relative to the maximum stress developed at collapse. The manner in which the high yield-point is obtained, whether by cold pressing, cold drawing, heat treatment, or through the use of stronger steels is inconsequential since the same collapsing strength will be realized for comparable yield strengths. In fact, unless penalized unduly by cost, the latter two methods are to be preferred since they involve less sacrifice in ductility and other desirable properties.

The results of the investigation by Jasper and Sullivan are summarized in Fig. 3, which reproduces the curves showing the relation between collapsing strength and the ratio of diameter to wall thickness for steels of different yield-points. The actual collapsing pressure can be calculated from the maximum stress at collapse by substitution in the Lamé equation:

$$P = \frac{2S}{d/t}\left[1-\frac{1}{d/t}\right], \tag{8}$$

where

P = collapsing pressure (lb. per sq. in.),

(Other symbols have their previous significance.)

This value, multiplied by 2 and divided by the desired safety factor, will give the maximum setting depth.

Setting depths obtained by the two methods vary considerably indicating to the operator the need for a general revision of the setting-depth data so that any error will be on the side of safety. According to the theory of Jasper and Sullivan it is impossible for the collapsing strength to exceed the theoretical value obtained from the Sturm equation, i.e. for any given ratio of outside diameter to wall thickness the collapsing strength cannot fall to the right of the envelope curve in Fig. 3. On this basis the collapsing strengths for Grade D casing with ratios of diameter to thickness of more than 28 exceed the possible maxima, and, if set in accordance with the recommended setting-depth data, the safety factor is correspondingly reduced. The sizes of casing which fall within this range are: 10 in., 33 lb.; 10¾ in., 40·50 lb.; 11¾ in., 47·00 lb. and all larger sizes. For corresponding sizes of Grade C casing the recommended setting depths conform closely with the calculated collapsing strengths. In the smaller sizes of casing, where the ratios of diameter to thickness are less than 28, the recommended setting depths are likewise generally greater than would be predicated by the theory of Jasper and Sullivan but, from a practical standpoint, the discrepancy is lessened by the fact that the physical properties of both Grade C and Grade D casing exceed the properties obtained by applying the respective corrective factors to Stewart's results for the low-strength lap-welded pipe. Were it not for the confidence engendered by long and generally successful experience with seamless-steel casing there would be cause for a feeling of uneasiness on the part of operators concerning the collapse hazard in setting the long strings of casing now frequently demanded. In any event the uncertainty can be removed by properly conducted investigation and, in view of the increasing importance of this subject to the oil industry, there is a moral obligation upon the tubular goods industry to set aside individual sales policies long enough to dissipate effectually all uncertainty.

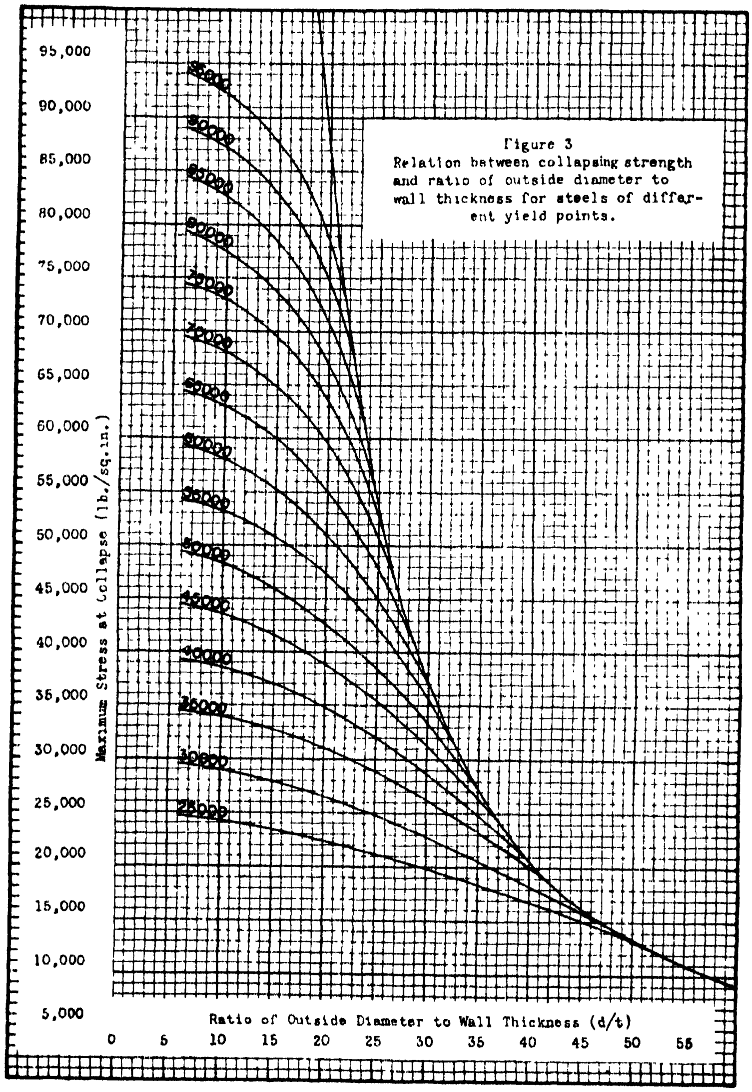

Figure 3
Relation between collapsing strength and ratio of outside diameter to wall thickness for steels of different yield points.

Bursting Strength.

The bursting strength of casing may be calculated by Barlow's formula:

$$P = \frac{2st}{D}, \tag{9}$$

in which

P = internal pressure (lb. per sq. in.),
s = ultimate tensile strength of metal (lb. per sq. in.),
t = wall thickness (in.),
D = outside diameter (in.).

If it is desired to determine the weight of pipe necessary for any given working pressure this can be done by substituting the value obtained by dividing the tensile strength of the metal by the desired factor of safety, substituting this result for s in equation (9) and solving.

Stretch of Casing.

In setting long strings of casing it is frequently necessary to calculate the stretch; this can be done by means of the following formulae which are based on Young's Modulus:

$$e = \frac{1}{2} \times \frac{12PL}{EA}, \tag{10}$$

where

e = stretch (in.),
P = weight of string (lb.),
L = length of string (ft.),
A = area of casing wall (sq. in.),
E = Young's Modulus (30,000,000 for steel).

Allowance for the buoyant effect of fluid in the well may be made by use of equation (11):

$$e = \frac{L^2}{2E}[\lambda - 2\rho(1-2\mu)], \tag{11}$$

in which e, L, and E have their previous significance, and

λ = density of steel (0·2833 lb. per cu. in.),
ρ = density of fluid (lb. per cu. in.),
μ = Poisson's ratio (0·28 for steel).

More convenient forms of this equation for suspension in air, salt water, and drilling mud are:

$$e = \frac{L^2}{1,470,760} \text{ for air} \tag{12}$$

$$e = \frac{L^2}{1,727,830} \text{ for salt water (sp. gr. = 1·154)} \tag{13}$$

$$e = \frac{L^2}{1,801,410} \text{ for drilling mud (sp. gr. = 1·44, wt. = 12 lb. per gal.)} \tag{14}$$

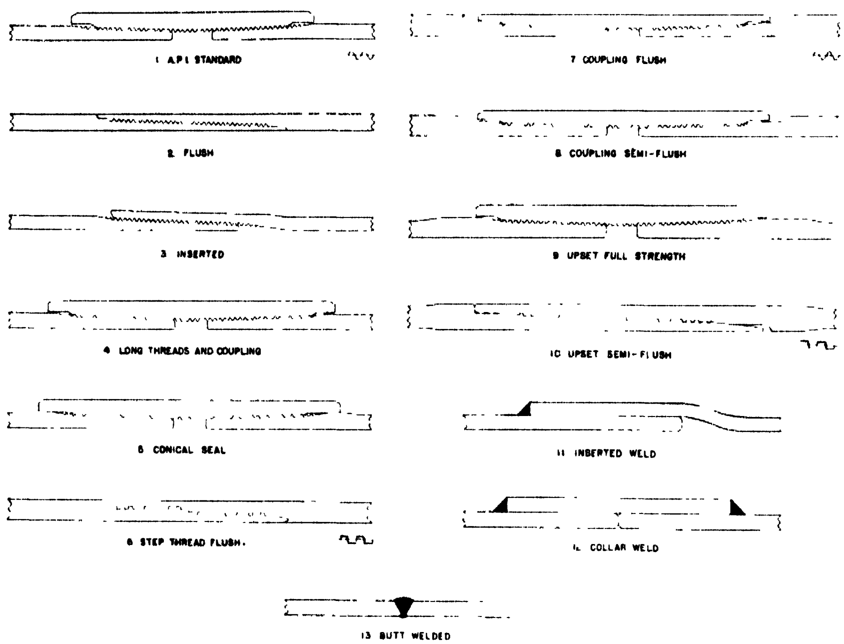

FIG. 4. Types of casing joint.

Where underground temperatures are high the suspended length of a string of casing may be corrected for the resulting expansion by equation (15):

$$L_t = L_0(1 + 0·0000069t) \tag{15}$$

where,

L_0 = length at surface temperature (ft.),
L_t = length at average well temperature (ft.),
t = difference between surface temperature and average well temperature (° F).

Joint Design.

The strength of the joint is second in importance, generally, to the collapsing strength of casing. If, however, a string accidentally becomes stuck while setting or it is necessary to recover a used string, then the strength of the joint becomes of paramount importance. At such times the joints are subjected to shock loads several times as great as the dead weight of the string they would ordinarily have to support. Frequently, in selecting a casing programme for deep wells it is necessary to depart from the conventional threaded and coupled joint either to obtain greater clearance or greater joint strength. Both of these advantages are desirable but both cannot be fully realized simultaneously in any threaded joint. Consequently, a knowledge of the important physical characteristics of the various types of joint is often advantageous. Reference to Fig. 4 will indicate the important features of the various types of joint referred to in the following discussion.

Joint Efficiency. The efficiency of a casing joint is the ratio of the tensile strength of the joint to the tensile strength of the body of the pipe. Regardless of the type of thread used, the maximum tensile strength of a threaded joint cannot exceed the tensile strength of a pipe having a wall section equivalent to that at the root of the first perfect thread. Therefore, the efficiency of any type of joint can be increased by increasing the area of metal under the first perfect thread, i.e. by upsetting; but any gain in joint strength obtained in this manner is realized at the expense of either internal or external clearance unless special couplings are used. Joint strength is determined by tensile tests of full-sized joints. These data have been used to calculate setting depths. Consequently, the approximate joint efficiency for any type of joint may be calculated from the recommended setting depth if the tensile strength of the casing material is known. For this purpose the average value for Grade C material may be taken as 85,000 lb. per sq. in. and as 105,000 lb. per sq. in. for Grade D material.

Since, as pointed out in the beginning, all the current casing problems arise in deep well drilling, it is necessary to consider joint design only as applied to Grade D casing. Rarely is it found necessary to use any other grade of casing with special joints, and when this occurs it is generally done to get added external clearance rather than increased joint strength.

Conventional Joint Designs. For purposes of the present discussion the joints which utilize the American standard form of thread (A.P.I. Pipe Specifications) will be considered in one group. This form of thread, also known as the Brigg's form, is a truncated V type of 60° included angle. The depth of the thread is 0·8 times the pitch for 10-thread casing and 1·0 times the pitch for 8-thread casing. The joint efficiency of casing with this type of thread (Type 1) varies ordinarily between 45 and 75%, this value being influenced by the size of the pipe, its wall thickness and the length of the threaded section [5, 1935].

There are several modifications of the conventional standard form of joint which find limited application for special purposes. In order to gain clearance where pull-out strength is not particularly important, an inserted flush joint can be used (Type 2). In this casing one end of each length is threaded internally and the opposite end is threaded externally. Since the threads for both sections are machined entirely from the pipe wall, the joint efficiency is very low (approximately 40% for 6⅝ in., 28·00 lb. casing and 36% for 9⅝ in., 43·50 lb. casing). Inserted joint casing (Type 3) belled at one end and threaded internally to mate with a standard male thread on the other end, gives a joint efficiency equivalent to the standard coupled joint but does

not, as is often mistakenly assumed, provide any additional clearance. This type of casing should have no place in modern operations.

Joints with Long Threads and Couplings. Other departures from the standard joint offer, within limits, the combined advantages of greater clearance and strength. All have longer threaded sections and couplings which is one reason for their greater strength. With Grade D steel the long type of coupling (Type 4) gives appreciably greater joint strength in all sizes of casing up to 13⅜ in. but only slight increase in strength for larger sizes. When the long type couplings are fabricated from heat-treated alloy steel (yield-point = 120,000 lb. per sq. in., tensile strength = 145,000 lb. per sq. in.) there are several alternatives which merit consideration for casing programmes for deep wells. Generally the threads are of the standard drill pipe form. i.e. they are rounded at both the crest and the root and have a height that is 0·570 times the pitch for 8-thread casing and 0·556 times the pitch for 10-thread casing. The shallower thread increases the strength slightly and the radius at the root reduces the stress concentration which may be of importance in preventing fatigue failure at the joints if drilling is to continue for a long period.

Since the physical properties of the alloy steel exceed so greatly those of the pipe, the couplings can be made much thinner without any sacrifice of joint strength. This results in greater clearance. For example, a flush coupled joint of this kind (Type 7) has a joint efficiency of 45% for 6⅝ in., 29·10 lb. casing and 47% for 9⅝ in., 54·20 lb. casing [8, 1934], a decided improvement over the corresponding values given above for the inserted flush-joint casing. A second modification of the joint with long threads and alloy steel coupling is a semi-flush type (Type 8) in which the joint strength is increased because the pipe threads have a larger pitch diameter and consequently there is a thicker section of metal under the first perfect thread. A joint strength equivalent to that of the standard joint is obtained and at the same time additional clearance is provided, sufficient frequently to make under-reaming unnecessary. A joint efficiency of 100% with no sacrifice of clearance is provided by the third alternative of this joint (Type 9) in which the high joint strength results from the use of externally upset pipe. In the fourth and simplest modification, alloy steel couplings used with regular long thread casing give both greater joint strength and greater clearance compared with the standard joint.

A slight modification of the standard joint (Type 5) in which a slight external upset is used to make possible a conical seal between the end of the coupling and the pipe, having the same taper as the threads, does not change the outside diameter or joint strength but introduces the three secondary advantages of added resistance to leakage, greater stiffness and shoulder support tending to impart increased resistance to joint fatigue failure from drilling.

Special Flush and Semi-Flush Joints. When expediency dictates the use of flush-joint casing the several advantageous features incorporated in the type which utilizes a two step square thread (Type 6) sum up to a very strong recommendation for its selection. One end of each length has a pin thread and the other end has a box thread so that no couplings are required. As the name indicates the joint is made up of two sections of different pitch diameters. In contrast with all other casing joints, the threads are cylindrical rather than tapered and this in conjunction with the square thread form lessens the tendency for the joint to jump under tensile loading. A precaution against leakage, made essential by the use of square threads, is provided by a conical section on the end of the pin which seats in a corresponding taper in the bottom of the box. At the base of the pin also there is a bevelled shoulder that seats against a corresponding bevelled shoulder on the end of the box. These shoulders act as an outside fluid seal and the direction of the bevel is such as to resist belling of the box under high torque loading. The joint efficiency remains constant at 55% for all sizes of casing between 6⅝ in. and 13⅜ in. [8, 1934]. This is equal to the joint efficiency of the standard joint in sizes of casing smaller than 9⅝ in. and exceeds that value in the 9⅝ in. and larger sizes. By slight external upsetting the joint strength can be increased greatly and in this form it has found application for drilling successfully through more than 2,000 ft. of heaving shale by the use of collapsible bits and chemically treated mud [7, 1936].

Another type, having unusually high joint efficiency (Type 10), utilizes a modified Acme tapered thread. It is a semi-flush joint and the high efficiency is obtained by slight upsetting both internally and externally. Thus, a sacrifice of internal clearance is compensated by a gain in external clearance. In order to improve the tightness the crests of the threads in the female half and the roots of the threads in the male half of this joint are parallel to the axis of the pipe and make contact when the joint is fully made up. The seal is further augmented by an internal tapered seat and an external square shoulder. The outside diameter of the joint for any given size of casing is the same regardless of the weight so that the joint efficiency increases as the weight decreases. The minimum joint efficiency for any size of this casing is 72% and the maximum is 100%. Casing of this type has also been used in several attempts to drill through heaving shale.

The high joint strength of these two forms of semi-flush inserted joint makes for economy in long strings by using a combination of Grade D casing on the bottom to provide adequate collapsing strength and Grade C material on top where it will ordinarily satisfy requirements for pull-out strength.

Undoubtedly the use of inserted, semi-flush joint casing for drilling will be extended in the future and, as more efficient collapsible bits are developed, the application will not be restricted wholly to drilling through heaving shale, especially since the smooth exterior surface of the joint section lends itself to drilling under pressure control.

Welded Casing Joints. The practicability of welding the joints as casing is run into the well has been demonstrated a number of times. The principal advantage is the elimination of leakage that is frequently experienced in long strings of casing with conventional threaded joints. For the most part experience has been confined to two forms of the slip-joint. In the first, which is of the bell and spigot variety (Type 11), the weld is applied in two layers between the bevelled end of the bell and the wall of the inserted end. In the second form the ends of the two lengths butt inside a close-fitting collar previously welded to one length of casing at the mill. The second form of slip-joint is to be preferred because of better alinement, flush interior, and closer fit between the parts to be welded. There is no gain in clearance with either form of the slip-joint and the load is carried in shear by the weld metal. For Grade C casing an average joint efficiency in excess of 95% can be obtained with either form [4, 1936], but, with present practice, 75% is the maximum value for heavier weights of Grade D

TABLE V.—*Comparative Data for Casing with Various Types of Joint**

Size (in.)	Weight per ft. (threads and coupling) (lb.)	Wall thickness (in.)	API. grade	Type of joint†	Thread form	Maximum outside diameter (in.)	Minimum inside diameter (in.)	Difference in clearance‡ (in.) outside	Difference in clearance‡ (in.) inside	Joint efficiency (%)	Setting depth (ft.) Tension§ (safety factor, 2¼)	Setting depth (ft.) Collapse (safety factor, 2)
6⅝	28·00	0·417	D	standard (1)	API.	7·390	5·791	0·000	0·000	58	7,076	7,101
	28·57	0·432	D	inserted flush (2)	„	6·625	5·761	+0·765	−0·030	40	4,840	7,443
	28·10	0·417	D	long threads and coupling (4)	„	7·390	5·791	0·000	0·000	72	8,752	7,101
	29·10	0·432	D	„ „ „	„	7·390	5·761	0·000	−0·030	72	8,734	7,443
	29·10	0·432	D	long threads and alloy steel coupling, flush (7)	rounded V	6·625	5·761	0·000	−0·030	45	5,465	7,443
	29·10	0·432	D	long threads and alloy steel coupling, semi-flush (8)	„	6·952	5·761	+0·438	−0·030	58	7,065	7,443
	27·64	0·417	D	inserted, step thread, flush (6)	square	6·625	5·791	+0·765	0·000	54	7,554	7,101
	29·10	0·432	D	„ „ „ upset, semi-flush	„	6·997	5·761	+0·393	0·000	85	10,410	7,443
	29·10	0·432	C	„ „ „	„	6·997	5·761	+0·393	0·000	85	8,258	5,616
	28·00	0·417	D	„ upset, semi-flush (10)	modified Acme	6·930	5·686	+0·460	−0·105	84	10,250	7,101
	28·00	0·417	C	„ „ „	„	6·930	5·686	+0·460	−0·105	84	8,000	5,616
	28·90	0·432	D	„ „ „	„	6·930	5·656	+0·460	−0·135	81	9,860	7,443
	28·90	0·432	C	„ „ „	„	6·930	5·656	+0·460	−0·135	81	7,700	5,890
7	30·00	0·423	D	standard (1)	API.	7·656	6·154	0·000	0·000	57	6,975	6,721
	30·30	0·423	D	long threads and coupling (4)	„	7·750	6·154	−0·094	0·000	71	8,602	6,721
	30·30	0·423	D	„ „ „ alloy steel coupling, semi-flush (8)	rounded V	7·336	6·154	+0·320	0·000	62	7,690	6,721
	29·71	0·423	D	inserted, step thread, flush (6)	square	7·000	6·154	+0·656	0·000	56	7,787	6,721
	30·00	0·423	D	„ „ „ semi-flush	„	7·369	6·154	+0·287	0·000	85	10,410	6,721
	30·00	0·423	C	„ „ „	„	7·369	6·154	+0·287	0·000	85	8,257	5,315
	30·00	0·423	D	„ upset, semi-flush (10)	modified Acme	7·310	6·049	+0·346	−0·105	81	9,910	6,721
	30·00	0·423	C	„ „ „	„	7·310	6·049	+0·346	−0·105	81	7,740	5,315
7⅝	33·70	0·430	D	standard (1)	API.	8·500	6·765	0·000	0·000	56	6,784	6,110
	34·00	0·430	D	long threads and coupling (4)	„	8·500	6·765	0·000	0·000	68	8,164	6,110
	33·04	0·430	D	inserted, step thread, flush (6)	square	7·625	6·765	+0·875	0·000	56	7,535	6,110
	33·70	0·430	D	„ „ semi-flush	„	8·017	6·765	+0·483	0·000	85	10,411	6,110
	33·70	0·430	C	„ „ „	„	8·017	6·765	+0·483	0·000	85	8,259	4,832
	33·70	0·430	D	„ upset, semi-flush (10)	modified Acme	7·920	6·660	+0·580	−0·105	81	9,810	6,110
	33·70	0·430	C	„ „ „	„	7·920	6·660	+0·580	−0·105	81	7,660	4,832
8⅝	43·00	0·487	D	standard (1)	API.	9·593	7·651	0·000	0·000	54	6,567	6,121
	43·70	0·487	D	long threads and coupling (4)	„	9·700	7·651	−0·107	0·000	64	7,659	6,121
	42·32	0·487	D	inserted, step thread, flush (6)	square	8·625	7·651	+0·968	0·000	55	7,724	6,121
	43·00	0·487	D	„ „ semi-flush	„	9·060	7·651	+0·533	0·000	85	10,415	6,121
	43·00	0·487	C	„ „ „	„	9·060	7·651	+0·533	0·000	85	8,262	4,841
	43·00	0·487	D	„ upset, semi-flush (10)	modified Acme	9·030	7·546	+0·563	−0·105	75	9,120	6,121
	43·00	0·487	C	„ „ „	„	9·030	7·546	+0·563	−0·105	75	7,120	4,841
9⅝	43·50	0·435	D	standard (1)	API.	10·625	8·755	0·000	0·000	52	6,305	4,417
	44·30	0·435	D	long threads and coupling (4)	„	10·625	8·755	0·000	0·000	60	7,144	4,417
	42·69	0·435	D	inserted, step thread, flush (6)	square	9·625	8·755	+1·000	0·000	56	7,943	4,417
	43·50	0·435	D	„ „ semi-flush	„	10·097	8·755	+0·528	0·000	86	10,495	4,417
	43·50	0·435	C	„ „ „	„	10·097	8·755	+0·528	0·000	86	8,325	3,493
	43·50	0·435	D	„ upset, semi-flush (10)	modified Acme	10·020	8·630	+0·605	−0·125	85	10,310	4,417
	43·50	0·435	C	„ „ „	„	10·020	8·630	+0·605	−0·125	85	8,050	3,493
	52·85	0·545	D	„ flush (2)	API.	9·625	8·535	+1·000	0·000	36	4,350	6,145
	54·20	0·545	D	long threads and coupling (4)	„	10·625	8·535	0·000	−0·220	60	7,228	6,145
	54·20	0·545	D	„ „ „ alloy steel coupling, flush (7)	rounded V	9·625	8·535	+1·000	0·000	47	5,700	6,145
	54·20	0·545	D	long threads and alloy steel coupling, semi-flush (8)	„	9·924	8·535	+0·701	0·000	55	6,675	6,145
	52·85	0·545	D	inserted, step thread, flush (6)	square	9·625	8·535	+1·000	0·000	56	7,943	6,145
	54·20	0·545	D	„ „ semi-flush	„	10·097	8·535	+0·528	0·000	85	10,405	6,145
	54·20	0·545	C	„ „ „ „	„	10·097	8·535	+0·528	0·000	85	8,254	4,862
	53·50	0·545	D	„ upset, semi-flush (10)	modified Acme	10·020	8·410	+0·605	−0·125	72	8,790	6,145
	53·50	0·545	C	„ „ „	„	10·020	8·410	+0·605	−0·125	72	6,860	4,862
10¾	55·50	0·495	D	standard (1)	API.	11·750	9·760	0·000	0·000	49	5,913	4,545
	55·80	0·495	D	long threads and coupling (4)	„	11·750	9·760	0·000	0·000	56	6,722	4,545
	54·21	0·495	D	inserted, step thread, flush (6)	square	10·750	9·760	+1·000	0·000	55	7,732	4,545
	55·50	0·495	D	„ „ semi-flush	„	11·191	9·760	+0·559	0·000	85	10,405	4,545
	55·50	0·495	C	„ „ „	„	11·191	9·760	+0·559	0·000	85	8,254	3,595
	55·50	0·495	D	„ upset, semi-flush (10)	modified Acme	11·140	9·635	+0·610	−0·125	80	9,650	4,545
	55·50	0·495	C	„ „ „	„	11·140	9·635	+0·610	−0·125	80	7,540	3,595
13⅜	68·00	0·480	D	standard (1)	API.	14·375	12·415	0·000	0·000	43	5,164	3,009
	68·10	0·480	D	long threads and coupling (4)	„	14·375	12·415	0·000	0·000	46	5,397	3,009
	66·10	0·480	D	inserted, step thread, flush (6)	square	13·375	12·415	+1·000	0·000	55	7,203	3,009
	72·50	0·514	D	long threads and coupling (4)	API.	14·375	12·347	0·000	−0·068	45	5,414	3,394
	72·50	0·514	D	„ „ „ alloy steel coupling, semi-flush (8)	rounded V	13·632	12·347	+0·743	−0·068	46	5,555	3,394
	70·60	0·514	D	inserted, step thread, flush (6)	square	13·375	12·347	+1·000	−0·068	58	6,978	3,394

* Data for joint with conical seal (Fig. 5, Type 5) may be considered the same as for standard API. joints. Efficiency of welded joints may be taken as 75% for all sizes, giving proportional setting depths in tension. Slip joints have the same outside diameter as corresponding standard API. size coupling.

† Figures in parentheses refer to Fig. 5.

‡ Differences in clearance are based on lightest weight for each size in this table.

§ Setting depth in tension for inserted, step thread, flush (Fig. 5, Type 6) calculated on maximum area of box with a stress of 47,500 lb. per sq. in.

casing and the joint efficiency may fall as low as 30% for lighter weights. Consequently, use is ordinarily restricted to water strings. The butt-welded joint (Type 13), which has not been very extensively used, has all the advantages not possessed by the slip type; the load is carried in tension by the weld, the joint efficiency is generally higher for both grades of casing (79 to 100%) and there is a gain in clearance. However, there are three disadvantageous features in welding casing; first, the difficulty in maintaining proper alinement during welding, second, the human element introduced by the welding operation, and third, the brittleness of the steel in the vicinity of the weld. The latter is a serious obstacle to recovery of long strings. The welding of casing must still be regarded as being in the development stage and further reduction to practice will be dependent upon the degree of success in overcoming these three inherent sources of potential difficulty. There is no acute necessity for welded casing strings in any case since the maximum setting depth is fixed by the collapsing strength, and several of the special threaded joints provide more than sufficient strength for these depths.

Casing programmes for deep wells merit detailed study since the cost of the casing may amount to as much as 35% of the initial investment and the possibility of successful operation may rest largely on the judgement exercised in the selection of the casing. The advantageous features of casing with flush or semi-flush joints should not be overlooked. In rock bit-drilling the size of the hole is an important factor since the smaller size bits generally average both more footage and faster drilling. The elimination of underreaming effects economy both in time and expense. Occasionally this type of casing will permit the setting of an emergency string without reducing the size of the oil string below the practical minimum if unexpected water or gas strata are encountered. The salient features of the various joint types are assembled for ready reference and comparison in Table V which may facilitate the selection of casing programmes.

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TUBING

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THE proportion of production cost which is chargeable to tubing is influenced largely by the conditions of service. For a representative group of more than 3,000 wells in the Mid-Continent and Gulf Coast fields over the 3-year period of 1933, 1934, and 1935, tubing-repair jobs averaged 5% of total-repair jobs and tubing-repair costs averaged 15% of total well-repair costs. The average cost of each tubing failure, including material, labour, and miscellaneous expenses was approximately $45.00.

Materials and Methods of Manufacture.

There are only two materials from which oil-well tubing is generally fabricated: wrought iron and basic open-hearth steel. Other materials have been tested or used to a limited extent such as, for instance, ingot iron, toncan iron, 1% copper steel. The object in every case was to increase the corrosion resistance and, since none has approached general usage, it may safely be concluded that the advantage, if any, did not offset the added cost. The continued, though limited, use of wrought iron indicates that there are some who believe it more resistant to the corrosive attack of oil-well fluids than steel. Granting to wrought iron the advantage of any doubt which may exist, it is still questionable whether its use at a higher cost can be justified on the basis of more economical service. All wrought-iron tubing is made by the lapwelded process.

Steel tubing is obtainable in three forms: lapwelded, seamless, and electric welded. Lapwelded steel tubing may be dismissed with the observation that it is suited for use only in shallow, low-pressure fields where there is no necessity for frequent pulling. Seamless-steel tubing is the standard and its performance is used comparatively to judge the quality of tubing made by any other process. Its properties are too well known to require discussion. Electric-welded tubing is made in both Grade C and Grade D, having properties comparable to the corresponding grades of seamless tubing. The process of manufacture is similar to that discussed in the chapter on Casing. Since tubing is generally subjected to more corrosive service than casing, by reason of its being in contact with moving fluids, it is quite important that electric-welded tubing be processed in such a manner as to equalize internal stress or to be fully normalized so as to lessen the probability of localized attack in the vicinity of the weld. It is impossible to weld without altering the structure of the metal.

For typical compositions and physical properties the reader is referred to the chapter on Casing.

Causes of Tubing Failures.

The primary causes of tubing failures are corrosion, wear by sucker rods, fatigue at the joints, and leakage at the joints. Local operating conditions determine which cause predominates. For instance, the wells in the Greater Seminole area are notable for wide deviation from the vertical, and this condition is clearly reflected in the record of tubing failures (see Table I) for a group of 211 pumping wells prior to May 1931, all of which were equipped with Grade C regular seamless tubing [2, 1936].

TABLE I

Record of Tubing Failures for 211 Pumping Wells in the Greater Seminole Area

Cause of failure	*Number of failures*	*Per cent. of total failures*	*Number of wells affected*	*Remarks*
Rod wear	220	53·8	80	principally at ends
Fatigue at threads	73	17·9	40	..
Joint leak	84	20·5	47	..
Parted joint	27	6·6	18	caused by rod failures
Worn coupling	5	1·2	3	..
Total	409	100·0	188	..

The effect of deviation from the vertical is plainly evident since 53·8% of all failures were the direct result of rod wear. In addition, the greater portion of the fatigue failures at the threads are also attributable to the same cause since the fluid-levels were high and pumping loads consequently moderate in the early period covered by this record.

The record of tubing-repair jobs for 3½ years subsequent to May 1931 for a group of 83 pumping wells, also in the Greater Seminole area, but which were equipped with Grade C upset seamless-steel tubing is given in Table II.

TABLE II

Record of Tubing Failures for 83 Pumping Wells in the Greater Seminole Area

Cause of failure	*Number of failures*	*Per cent. of total failures*	*Number of wells affected*
Rod wear	3	4·8	3
Fatigue at threads	40	63·5	18
Joint leak	18	28·4	14
Corrosion	2	3·2	2
Total	63	100·0	37

The reduction in the number of failures due to rod wear resulted from the greater thickness of metal at the threads. This was still not sufficient, however, to prevent a large number of joint failures.

TABLE III

Record of Tubing Failures for 200 Pumping Wells at Smackover for 9 months in 1931

Cause of failure	*Number of failures*	*Per cent. of total failures*	*Remarks*
Fatigue at threads	163	52·5	..
Corrosion	59	19·3	..
Split tubing	48	15·7	rod wear and corrosion
Joint leak	38	12·5	..
Total	308	100·0	..

In contrast is the record given in Table III, of failures

of Grade C regular seamless-steel tubing in about 200 pumping wells at Smackover over a period of 9 months in 1931 [3, 1933].

In this field corrosion was directly responsible for 19·3% of the failures and responsible for a part, at least, of the 15·7% charged to split tubing and the 12·5% charged to joint leaks.

An interesting comparison between the distribution of failures in regular and upset seamless-steel tubing in similar service, also at Smackover, is given in Table IV [3,1933] to bring out the advantage of the latter type.

TABLE IV

Comparison of Failures in Regular and Upset Tubing in Similar Service at Smackover

Type of Tubing	*Regular*	*Upset*
Number of wells	20	17
Average age of tubing (months)	39·9	35·5
Average failure per well from.		
Fatigue at threads	8·10	1·30
Corrosion	0·25	0·47
Split tubing	0·75	0·17
Joint leak	0·15	0·53
Total	9·25	2·47

Consideration of the foregoing data, which are typical, discloses that the greater part of tubing-repair jobs is the result of failure of one kind or another at the joints. One method of reducing well-repair cost from this cause is to use upset tubing. For severe pumping conditions the use of upset tubing is imperative and Rogers [3, 1933] has clearly shown that the added thickness of metal behind the threads is a distinct advantage under corrosive conditions also. Therefore, it becomes apparent that it is probably most economical in the long run to standardize upon upset tubing. A word of caution should be given, however, to make certain that the full advantage of this course may be realized. In some corrosive fields, of which Smackover is an outstanding example, ordinary upset tubing is subject to rapid, localized corrosion in a narrow zone adjacent to the upset section. A typical example of this action is pictured in Fig. 1. The attack is confined to a comparatively narrow circumferential ring at the end of the section which was heated for upsetting. Because of the internal strains and structural differences at this point the metal is anodic to the sections on either side and the rate of corrosion is so accelerated that complete perforation of the wall may take place in as short a time as 6 months. Fortunately, this type of failure may be completely eliminated if the tubing is normalized after the upsetting operation. This remedy is both effective and inexpensive.

From the foregoing discussion it is apparent that from 50 to 90% of tubing failures occur at the joints. Also, while the total number of failures can be reduced by the use of upset tubing the ratio of joint failures to total failures is not greatly altered. Frequently, in deep wells of both the Mid-Continent and Gulf Coast fields, leakage at the joints seriously interferes with production after the tubing has been pulled only a few times. In order to improve this condition it is a common practice of pipe manufacturers to machine the tubing threads to the high side of the limiting pitch diameter and the coupling threads to the low side. Thus the stand-off value of the joints is increased and a greater number of perfect threads left to allow for the creep which takes place each successive time the joints are made up. While joint leakage may be deferred in this way, frequently the torque required for proper make-up is greater than can be applied in the field, and the reduced area of thread contact is conducive to premature fatigue failure in the threads.

In spite of the knowledge that the standard tubing joint is poorly designed to resist failure by fatigue or corrosion fatigue, until recently no attempt has been made by the tubing manufacturers to effect improvement. They have been exceedingly slow in applying knowledge and experience gained from the improvement of drill pipe, tool joints, and casing to tubing. A considerable amount of tubing with rounded V-threads (drill-pipe threads) has been made and there is a growing sentiment in favour of making this type of thread standard for both casing and tubing. Theoretically this change should greatly improve the fatigue strength of the joint, but practically it is probable that the betterment will be comparatively small and not at all commensurate with the need. The basis for this statement is the fact that the thread-cutting tools rapidly wear on the corners and, very soon after sharpening, the threads that they cut are actually rounded at the root instead of having the sharp corners of the theoretical standard truncated V-thread.

The adaptation of a drill-pipe joint to tubing is illustrated in Fig. 2. In this joint there is an external seal and shoulder support provided between the end of the coupling and the pipe by mating surfaces machined to the same taper as the threads. In the coupling the conical seating surface is substituted for the conventional counterbore or recess. Both pipe and coupling are interchangeable with products which comply with the A.P.I. Pipe specifications. The two important advantages of this joint, both of which are imparted by the conical-seating surfaces, are: an external fluid seal in addition to that resulting from the contact of the threads, and increased fatigue strength by reason of the resistance to bending. In some recent tests [1] joints selected at random, made up 5 times with an advance in make-up of $\frac{1}{4}$ turn to $\frac{1}{2}$ turn each successive time, did not leak at the shoulder seal in a hydrostatic test at 8,000 lb. per sq. in. There is but little doubt that this joint should demonstrate its superiority by a reduction in the number of joint failures. Other special types of tubing joint which embody principles used heretofore only for drill pipe and casing are in process of development, indicating that this problem, which has already been neglected too long, is finally receiving the attention which its seriousness merits.

Protective Coatings.

The restriction of cost on tubing is such as to preclude the use of corrosion-resistant alloy steels and, as indicated previously, the materials that are not included in this restriction are not appreciably more corrosion-resistant than ordinary medium-carbon steel. In service where the corrosion is so severe as to necessitate some remedial measure the only recourse that is economically feasible is the use of galvanized tubing. The extension of service life and the reduction in the number of early failures will nearly always far outweigh the greater initial cost of approximately 15%. It is important that galvanized tubing should be the upset type so that joint failures from the combined action of corrosion and rod wear will not terminate its usefulness before the full protective benefit of the galvanizing has been realized. Although desirable, there has been no entirely satisfactory method developed for coating the threads with zinc. For especially severe service some tubing

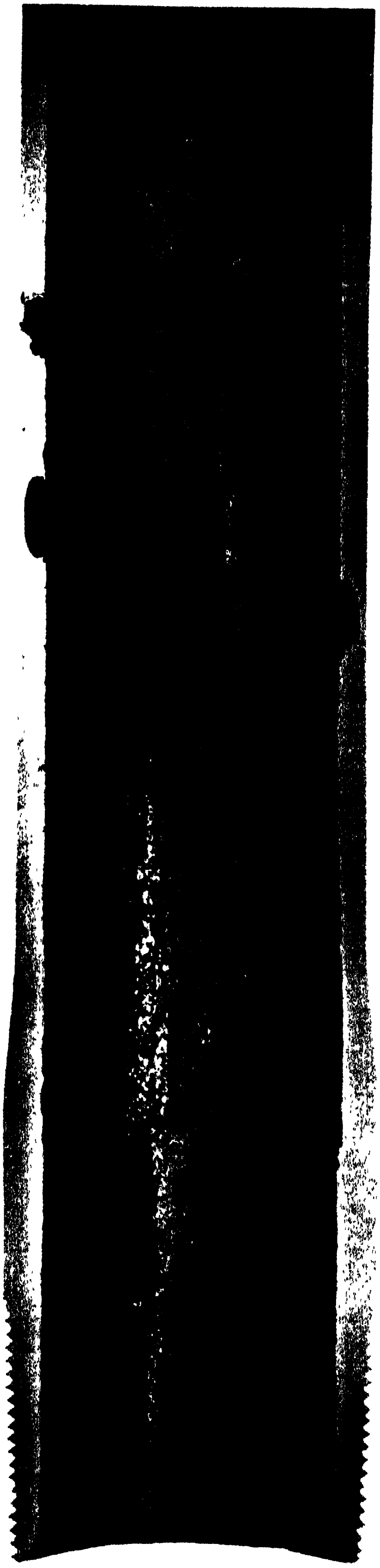

FIG. 1. Localized, accelerated corrosion in unnormalized upset seamless steel tubing after 6 months' service

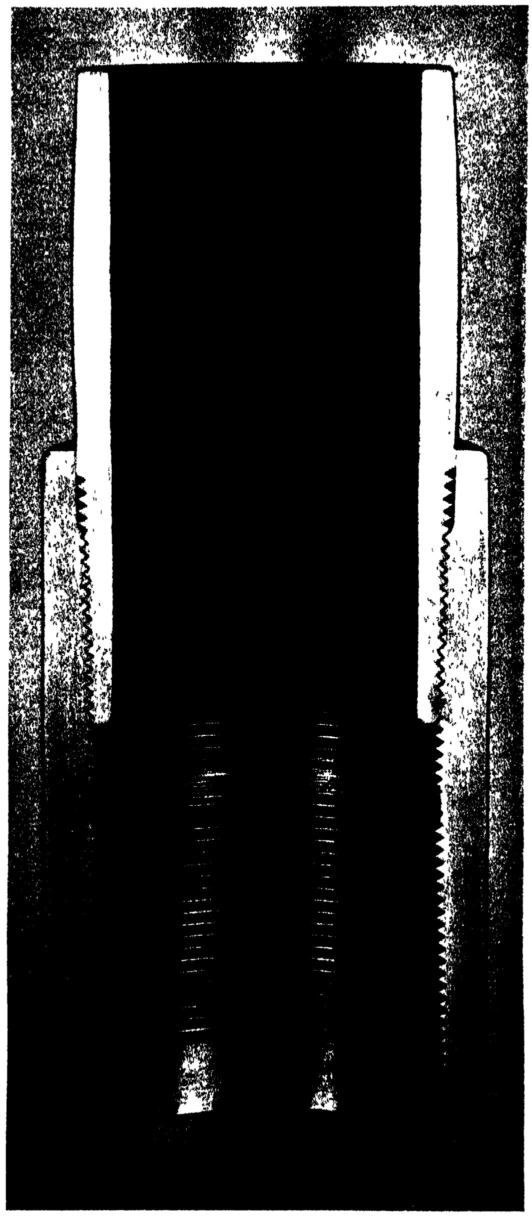

FIG. 2. Improved tubing joint with tapered fluid seal and support against bending

has been galvanized after threading. The metal-spray process offers a possible method for coating threads but it has not been thoroughly investigated.

The benefit derived from galvanized tubing is almost directly proportional to the thickness of the coating. By special methods it is practicable to obtain a coating having a minimum weight of 2½ oz. per sq. ft., an increase of more than 20% in the thickness of the coating. In most cases this extra weight of coating is justifiable.

In some fields where tubing corrosion is troublesome and costly the damage is largely confined to the portion of the string below the working-fluid level of the well, and here it is more economical to use galvanized tubing only in that section. In other fields the attack is distributed over the interior of the entire string so that it is necessary to use galvanized tubing exclusively.

No general policy for the use of galvanized tubing can be advanced since each well is an individual problem. However, if the service life of tubing is less than 3 years, because of failure from corrosion, it will generally be economical to use galvanized tubing.

In a few exceedingly corrosive wells in Kansas, having a depth of less than 1,000 ft., cement-lined pipe has been used with marked success. Several potential objections to the use of cement-lined pipe in pumping wells of average depth are so obvious as to justify the opinion that its use will be restricted to gas-lift, repressuring, and salt-water disposal operations.

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SUCKER RODS

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As the means almost universally employed for actuating oil-well pumps, sucker rods comprise an important part of the equipment used to produce petroleum from wells that will not flow naturally or that cannot be operated economically by induced methods of flow. Few problems in the application of metals to industry are as complicated as the selection of steels that are suitable for the fabrication of sucker rods. Because of the limitation on the size of sucker rods which is imposed by oil-well tubing, the con stant demand for greater durability can be satisfied only through the utilization of special steels with properties that make them particularly fitted for this kind of service. No single type of steel is capable of giving both satisfactory and economical sucker-rod service under all conditions of operation. Therefore, if the minimum in expense and well repairs is to be realized, the selection of sucker rods must be predicated not only upon a knowledge of the properties of steels, but also upon a thorough familiarity with operating conditions. There is much valuable information available on both of these aspects which is the result of an unusual amount of both laboratory and field experimentation that have been in progress since 1930. The field experimentation has been concentrated largely in the fields of the Mid-Continent, where pumping conditions are, in general, more severe than elsewhere. All factors that make for severe service, depth, high water/oil ratios, rapid pumping rates, and hydrogen sulphide, are present in the oilfields of Kansas and the Greater Seminole Area and at Oklahoma City. This territory is, consequently, a most valuable proving ground for the evaluation of the numerous steels that are being used and proposed for the fabrication of sucker rods.

Carefully compiled records show that there is ample economic justification for extensive development work, even though it is applied to a comparatively simple part of oil-production equipment. For example, in a representative group of more than 3,000 pumping wells in fields of the Mid-Continent and Gulf Coast during the two years of 1933 and 1934, sucker rods were responsible for 15·5% of the total well-repair jobs and for 17·5% of the total well-repair expense. The average cost of each sucker-rod failure, including labour, material, and miscellaneous expenses, for the same group of wells during the same period was $18.85.

Knowledge of Conditions Essential

Since one type of sucker rod cannot be used with economy under all conditions, it is necessary to give attention to the factors which should be considered in deciding what type to use in any certain well or field. Too much stress cannot be given to the value of individual well records when making a selection of equipment or, in the case of troublesome wells, to the importance of a complete analysis of the operating conditions.

The Nature of Sucker-rod Service.

When a metal is subjected to repeated stressing the action is termed fatigue. The endurance or fatigue limit of a metal is the measure of its ability to resist the action of fatigue or repetitive stressing, and it is defined [10] as the greatest unit stress that may be applied to the metal for an indefinite number of cycles without causing it to fail. The endurance limit of a metal is not a fixed property such as, for instance, its tensile strength; it is influenced by various factors, among which the most important are the nature and range of the stress, the design of the stressed part, and the environment in which it operates. The action of cyclic stresses on a metal in the presence of a corrosive medium is termed corrosion fatigue [8, 1926], and the corrosion endurance limit of a metal may be defined as the greatest unit stress that may be applied to the metal for a given number of cycles under given conditions of corrosion without causing it to fail. It is necessary to specify the number of cycles of stress and the conditions of corrosion, since it is obvious upon reflection that the limiting stress required to cause failure is influenced to a large extent by the rate of stress application, i.e. time of exposure to the corrosive medium. Further, it is equally clear that the corrosion endurance limit approaches zero as the time of exposure to the corrosive medium increases, and that if the time were sufficiently long, even unstressed metal would be totally destroyed by corrosion.

A qualitative consideration of the load conditions in the sucker-rod string of a pumping well during one complete stroke is sufficient to show that the action of fatigue is the cause of all sucker-rod failures. On the upstroke the rods are subjected to a stress that is made up of the weight of the sucker-rod string and fluid column, the friction throughout the system from the pump plunger to the stuffing-box, and the inertia load introduced when the total mass of rods and fluid is accelerated from rest to the maximum velocity of the polished rod. On the downstroke the rods are subjected to the weight of the sucker-rod string less the buoyant effect of the fluid column, the friction in the system from the stuffing-box to the pump plunger, and the effect of decelerating the mass of the rods from the maximum velocity of the polished rod to rest. It is clear, then, that, except for a few rods just above the plunger, all the rods in a string pumping a well are subjected to cycles of stress, between maximum and minimum limits in tension, the frequency of which is the rate at which the well is operating. If the well produces both oil and water, then the rods are subjected to the action of corrosion fatigue.

Calculation and Measurement of Sucker-rod Loads.

In choosing the most suitable type of sucker rods the two most important factors to consider are: first, the maximum stress which they must withstand, and second, the degree of corrosivity of the fluid produced. Manufacturers of pumping equipment have prepared charts and tables which provide a reasonably close approximation of the maximum polished rod load for any given set of conditions. While in one or two instances these charts and tables are based on dynamometer studies of pumping wells, most of them are the result of theoretical calculation. One

formula [5] which is frequently used for this purpose is as follows:

$$W_t = W_r + W_f \times \left(1 + \frac{S \times L}{5{,}400}\right), \quad (1)$$

where W_t = total polished rod load (lb.),
W_r = weight of sucker rods (lb.),
W_f = weight of fluid column (lb.),
S = pumping rate (strokes per min.),
L = length of stroke (in.).

Another and more accurate formula [6] is given by equation (2):

$$W_t = \left[W_r L + \frac{S}{3}(d^2 - d_r^2)(L-h)\right](1 + 0{\cdot}0000142 l N^2) + F, \quad (2)$$

in which

W_t = total polished rod load (lb.),
W_r = weight of rods (lb. per ft.),
L = length of rod string (ft.),
S = specific gravity of fluid,
d = diameter of pump plunger (in.),
d_r = diameter of sucker rods,
h = height of fluid-level above pump (ft.),
l = length of stroke (in.),
N = number of strokes per min.,
F = total friction in system due to plunger, fluid, rods, and stuffing-box (lb.).

The greater accuracy of equation (2) is introduced by the corrections applied for the buoyant effect of the fluid column, the working fluid-level in the well, and the friction.

Any theoretical formula for calculating the polished rod load of a well is only an approximation at best, however, since it is necessary to estimate the working fluid-level in the well, the amount of gas present in the fluid column, the specific gravity of the well fluid, and the several friction factors. The method to be preferred, whenever possible, is the actual measurement of the polished rod load with a dynamometer. Several types of dynamometers have been developed for this purpose. Most of the dynamometers measure the instantaneous loads either by a calibrated spring or by pressure exerted on a fluid system by a diaphragm or piston and record these loads through magnifying mechanical linkages. It has been shown [15, 1934] by direct comparison with electrical measuring and photographic recording instruments of great sensitivity that both the fluid-type and spring-type dynamometers tend to damp out the peak loads and do not record them accurately either in magnitude or in the correct phase relationship to the position of the polished rod. Furthermore, their accuracy appears to decrease as the pumping speed increases.

A simple strain-gauge type of dynamometer has been developed [11, 1935] which fulfils the need for a rugged, indicating instrument that can be quickly and conveniently used by operators without technical training. The dynamometer clamps on the polished rod and indicates the elastic deformation of the polished rod by means of a dial gauge that is calibrated to read the load or pull directly in pounds. The accuracy of the instrument is affected by bending of the rod to which it is attached, but it is not influenced by bending in one plane, and the error can be minimized by attaching it to the polished rod so that its immune plane coincides with the plane of greatest bending of the polished rod. It is necessary to estimate the phase relationship of instantaneous load to polished rod position so that the real utility of the instrument is limited to the determination of the maximum and minimum loads during a pumping cycle. It is not well adapted for measuring horse-power input at the polished rod. When its apparent limitations are kept in mind, this dynamometer is very useful, for instance, in determining why the sucker rods fail much more frequently in one well than they do in an adjacent well of apparently similar characteristics. It can also be applied to the determination of pull-rod loads.

For a more accurate and detailed study of sucker-rod loads a magnetic strain-gauge dynamometer [4, 1935] is available which combines adequate ruggedness, increased accuracy, and ease of handling to such a degree that it is definitely superior to other recording dynamometers. It is pictured in Fig. 1. The load-measuring unit consists of a compression tube upon which two sets of pole pieces with coils are mounted at an angle of 180° to each other. A fixed armature is positioned between the pole pieces so that there is an air gap between them. The coils and pole pieces comprise two variable impedances in a Wheatstone bridge, the other two arms of which are resistances for adjusting the balance of the bridge when no load is on the strain gauge. When a load is placed on the compression tube the air gap is changed and the bridge circuit is unbalanced to an amount that is proportional to the load. High-frequency alternating current, provided by a small motor-generator set operating from a 6-volt storage battery, is used for the power supply. The current in the bridge is rectified and actuates an oscillograph element which is mounted on a reducing mechanism operated by a cord attached to the walking beam. A beam of light is focused on a mirror in the oscillograph and is reflected to a ground glass screen where it can be observed visually or recorded photographically. Horizontal displacement of the light beam is proportional to the polished rod movement, and vertical displacement is proportional to the polished rod load. A closed card is obtained from which instantaneous loads and polished rod horse-power can be calculated. The strain gauge is placed around the polished rod between the hanger and polished rod clamp, so that it carries the entire load of the well on the compression tube. Contact plates with rounded seating surfaces are used at either end of the gauge so that any bending of the polished rod has no effect on the load in the compression tube. Equally simple tension-type magnetic strain gauges are provided for measuring pull-rod loads; the same recording system is used. The accuracy of this instrument is within 2% of the true loads; it is readily calibrated in a tensile-compression testing machine.

Corrosion Fatigue Causes Failures.

Corrosion fatigue was alluded to briefly in the discussion of the nature of the service for which sucker rods must be designed. This subject merits more detailed consideration, since it is equally as important as the working load and is undoubtedly the direct cause of practically all sucker-rod failures other than those which occur in the joints. Oil-well waters are invariably brines of varying degrees of salinity. Usually they are entirely free of dissolved oxygen as far as can be determined by ordinary methods of analysis, and this fact probably explains why their corrosivity is apparently but slightly influenced by the nature and amount of the dissolved salts. The factor having the greatest effect on the severity of corrosive attack on subsurface equipment in oil-wells is the water/oil ratio. When the amount of water exceeds 30% of the total fluid produced, corrosion is quite likely to proceed at an advanced rate. The

corrosion of sucker rods proceeds, almost without exception, by the process of pit formation.

The simultaneous action of corrosion and cyclic stressing is particularly damaging to all ordinary steels. According to the most generally accepted explanation [3, 1932], failure from corrosion fatigue occurs in two stages [9, 1927]. During the first stage of the action the metal is subjected to damage from the two causes, viz. corrosion and fatigue, to such a degree that failure would eventually result even if all further corrosion were arrested. Each of the two contributing factors intensifies the effect of the other, since metal under stress has a higher solution pressure and therefore corrodes more rapidly than when it is unstressed, while the formation of pits on the surface, as a result of corrosion, causes marked stress concentration. When the maximum stress (imposed by the conditions of operation and augmented by the stress concentration from pitting) exceeds the endurance limit cracks form at the base of the pits, which marks the beginning of the second stage of failure. During this final stage the cracks are propagated gradually by stress concentration effects at an ever-increasing rate until the cross-sectional area is finally reduced to such a degree that rupture follows suddenly. Sucker rods in the first stage of corrosion fatigue are illustrated by Fig. 2; these rods were operated under very corrosive but light pumping conditions. Fig. 3 pictures rods in the second stage of corrosion fatigue as a result of operating under corrosive and heavy pumping conditions. Failure caused by stress concentration at the base of a small pit is shown in Fig. 4, in which the characteristic progressive nature of fatigue failure proceeding at a gradually increasing rate is clearly evident.

When the gas associated with the oil and water produced by a well contains hydrogen sulphide as one of its constituents the severity of service conditions is very greatly increased. The hydrogen sulphide increases the corrosivity of the water, promotes pitting action, and also causes embrittlement of sucker rods. Relatively short exposure to this gas in the presence of water will embrittle steel seriously even though there may be only very slight corrosion [14, 1935]. Steels vary in their susceptibility to embrittlement by hydrogen sulphide; of the ordinary steels, those containing nickel are least affected. The extent of embrittlement is greater in steels with high residual internal stress [12, 1930], thereby indicating that ordinary steels in the heat-treated condition are not suited for such service.

Properties of Sucker Rods

Selection of sucker rods is facilitated by a knowledge of the properties of the steels used and the significance of these properties in terms of probable service. Typical compositions of the numerous types of steel and iron used for sucker rods are given in Table I.

The static physical properties of sucker rods and conditions of heat treatment are given in Table II.

TABLE I

Chemical Compositions of Sucker Rods

Type	Constituent, %								
	Carbon	*Manganese*	*Phosphorus*	*Sulphur*	*Silicon*	*Chromium*	*Nickel*	*Molybdenum*	*Other constituents*
S.A.E. 1035	0 370	0·830	0·018	0·033	0·110	..	..	..	..
S.A.E. 1045	0·450	0·840	0·027	0·041	0·210	..	..	..	..
S.A.E. 1050	0·510	0·730	0·015	0·047	0·180	..	..	..	..
S.A.E. T1340	0·380	1·910	0·023	0·016	0·210	..	..	..	..
S.A.E. 2315	0·140	0·550	0·012	0·032	0·140	..	3·500	..	..
S.A.E. 3130	0·340	0·650	0·015	0·020	0 190	0 580	0·990	..	..
S.A.E. 4130	0·310	0·620	0·013	0·020	0·240	0·720	..	0·210	..
S.A.E. 4615	0·180	0·510	0·012	0·006	0·230	..	1·850	0·240	..
1 25% manganese	0·360	1·170	0·024	0·021	0·190	..	..	..	..
Toncan iron	0·050	0·290	0·009	0·006	0·050	..	..	0·110	0·510 copper
Wrought iron	0·030	0·040	0·083	0·012	0·160	..	..	..	4·200 slag
Nickel wrought iron	0 030	0·040	0·077	0·027	0·110	..	3·000	..	2·750 slag
Nickel iron	0·030	0·010	0·003	0·006	0·030	..	3·520	..	..
Nickel molybdenum iron	0·040	0·130	0·002	0·007	0·030	.	2·900	0·140	..

TABLE II

Static Physical Properties of Sucker Rods

Type	Heat treatment,* ° F.			*Yield-point (lb. per sq. in.)*	*Tensile strength (lb. per sq. in.)*	*Elongation (% in 2 in.)*	*Reduction of area (%)*	*Charpy impact (ft.-lb.)*	*Brinell hardness number*
	Quench	*Normalize*	*Draw*						
S.A.E. 1035	..	..	..	55,500	88,500	31·3	56·4	30·3	169
S.A.E. 1045	..	1,600	..	62,300	96,500	28·3	52·3	19·2	191
S.A.E. 1050	W 1,550	..	1,100	100,700	123,200	21·5	59·4	29·7	230
S.A.E. T1340	..	1,550	..	72,900	118,200	23·5	56·3	32·1	·235
S.A.E. 2315	..	1,600	..	59,900	79,700	31·3	64·5	39·7	167
S.A.E. 3130	..	1,600	..	81,900	100,500	27·8	70·6	51·8	213
S.A.E. 4130	W 1,550	..	1,150	111,300	128,500	16·6	67·2	40·5	267
S.A.E. 4615	..	1,600	1,100	68,000	84,700	29·0	66·0	33·7	171
1·25% manganese	..	..	..	71,300	100,000	28·8	63·9	34·6	206
Toncan iron	..	..	..	43,100	51,900	43·3	80·5	55·1	106
Wrought iron	..	..	..	42,100	47,700	33·6	46·4	19·9	74
Nickel wrought iron	..	..	..	58,100	63,900	31·0	50·2	24·0	149
Nickel iron	..	..	..	47,900	58,100	40·8	72·3	44·5	125
Nickel molybdenum iron	..	..	..	52,500	63,600	37·8	70·3	43·5	140

* W indicates water quench.

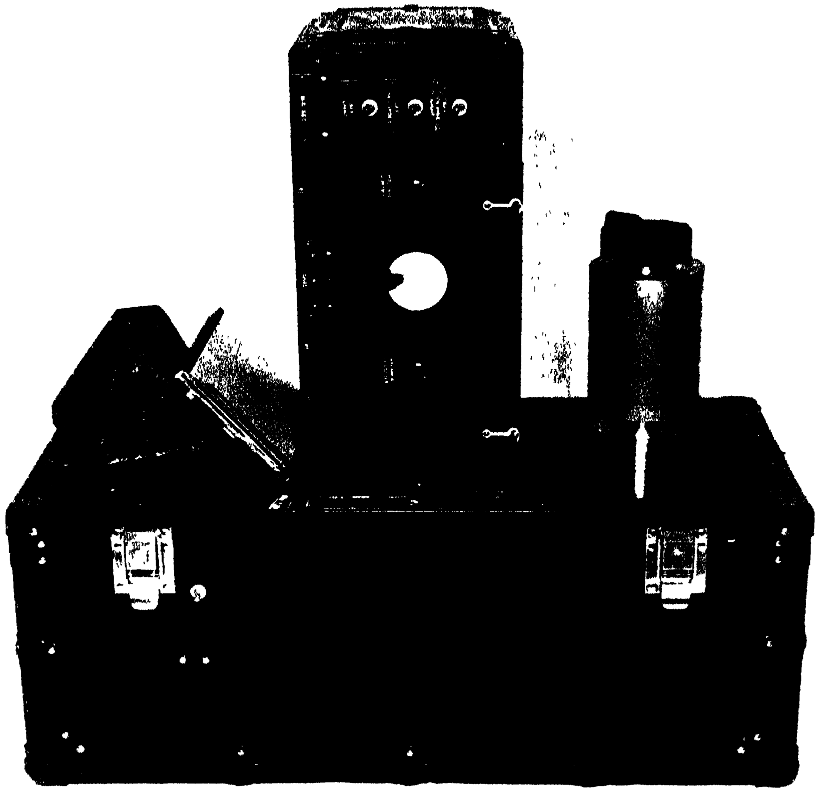

Fig. 1. Magnetic strain gauge dynamometer showing viewing hood, film holder, recorder, strain gauge, and carrying case containing the motor generator set

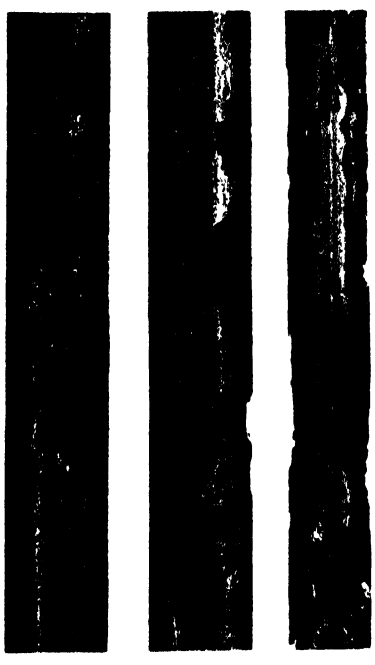

Fig. 2. Sucker rods which, although severely pitted, are in the first stage of corrosion fatigue because of low working stresses

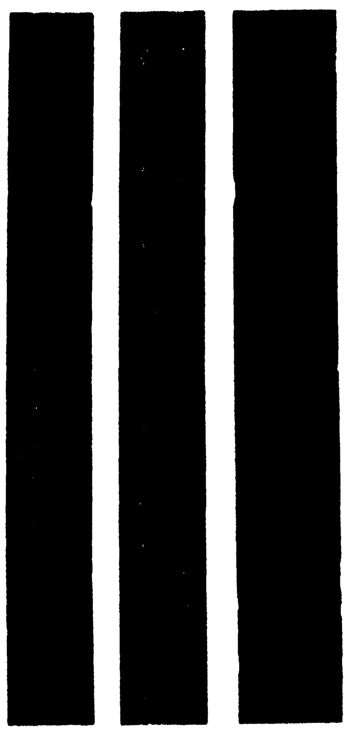

Fig. 3. Sucker rods showing the transverse cracks characteristic of the second stage of corrosion fatigue

The experimentally determined endurance properties [13, 1933] of sucker-rod steels are given in Table III. The values were determined for 10 million cycles of stress reversal, and the corrosion and sulphide corrosion fatigue tests were made with the samples immersed in oil-well brine free of oxygen; in the latter tests the brine was saturated with hydrogen sulphide. The damage ratios given in Table III indicate the extent to which the endurance limits are lowered by corrosion and sulphide corrosion. The materials which suffer least damage from both corrosion and sulphide corrosion fatigue are the low-carbon nickel steels and irons.

The reason for this will be explained briefly. Sucker rods are frequently operated so that the unit stress exceeds 30,000 lb. per sq. in. At the base of corrosion pits this may be intensified by a factor of 1·5 to 2·0, with the result that the stress at such points considerably exceeds the corrosion endurance limit. If this localized stress exceeds the yield-point also, there will be a local yielding accompanied by a redistribution of stress. However, if the yield-point is so high that the localized stress does not exceed it, there can be no redistribution of stress, but instead a fatigue crack will form and eventually progress to failure. Experience indicates that the yield-point should not be more than 3 times the corrosion endurance limit. A high degree of toughness is always desired, and the reduction of area is a more reliable index of this property than the elongation.

TABLE III

Endurance Properties of Sucker Rods

Type	Heat treatment,* ° F.			Endurance limit (lb. per sq. in.)			Damage ratios	
	Quench	Normalize	Draw	Air (AL)	Corrosion (CL)	Sulphide corrosion (SL)	CL/AL	SL/AL
S.A.E. 1035	..	.	..	40,600	24,600	10,600	0·61	0·26
S.A.E. 1050	W 1,550	..	1,100	66,900	25,600	14,100	0·38	0·21
S.A.E. T1340	..	1,550	..	56,400	29,400	12,100	0·52	0·21
S.A.E. 2315	..	1,600	..	51,900	31,600	23,900	0·61	0·46
S.A.E. 3130	..	1,600	..	55,100	31,600	15,900	0·57	0·29
S.A.E. 4130	W 1,550	.	1,150	70,100	26,900	14,100	0·38	0·20
S.A.E. 4615	..	1,600	1,100	48,600	33,100	22,400	0·68	0·46
1·25% manganese	..	..	..	48,900	19,600	14,600	0·40	0·30
Toncan iron	..	..	..	36,400	16,900	11,900	0·46	0·33
Wrought iron	..	..	..	30,400	19,600	16,400	0·64	0·54
Nickel wrought iron	..	..	..	42,600	25,100	18,600	0·59	0·44
Nickel iron	..	..	..	39,600	26,900	19,100	0·68	0·48
Nickel molybdenum iron	..	..	..	45,100	25,400	21,900	0·56	0·49

* W indicates water quench.

The endurance limits are not the values that would apply to service conditions [13, 1933], largely because the manner and the rate of stressing are not comparable with those of actual service, but they are reliable for comparing and evaluating sucker rods for the different kinds of service.

Selection of sucker rods may be facilitated by reference to Table IV, which classifies them in accordance with the conditions of service for which they are suited.

TABLE IV

Classification of Sucker-rod Materials according to Service Conditions

Type of service					
Non-corrosive		Corrosive			
		Non-sulphide		Sulphide	
Light ⟶	⟶ Heavy	Light ⟶	⟶ Heavy	Light ⟶	⟶ Heavy
S.A.E. 1035 S.A.E. 1045	S.A.E. 1050 heat treated S.A.E. 3130 S.A.E. 4130 heat treated 1·25% manganese S.A.E. T1340	S.A.E. 1035 S.A.E. 1045 Toncan iron Wrought iron	1·25% manganese S.A.E. T1340 S.A.E. 3130	1·25% manganese Wrought iron S.A.E. 4615	Nickel wrought iron Nickel iron Nickel molybdenum iron S.A.E. 2315 S.A.E. 4615

Selection of Sucker Rods

While sucker rods should be selected with due regard to all the physical properties of the steel from which they are fabricated, some of these properties are of much greater importance than others. The most important property is the endurance limit for the conditions of service under which they will operate. Under corrosive conditions there is no relation between the endurance limit and tensile strength, and the latter property is, therefore, of slight import. The second most important property is the yield-point, and the steel should be selected so that this property has a more or less definite relationship to the endurance limit [14, 1935].

In corrosive fields where pitting is severe the more costly, low-carbon, nickel steels with comparatively low yield-points and high corrosion endurance limits are most economical, but in fields where corrosion and pitting are less severe satisfactory service is obtained from the less costly, medium-carbon steels with higher yield-points.

Undercut Sucker Rods

Numerous attempts have been made to develop a joint better able to resist fatigue than the design adopted as standard by the American Petroleum Institute. Space does not permit discussion of them [16, 1934] other than a brief

description of the undercut joint, the only one that has approached general use. From Fig. 5 it can be seen that the undercut joint differs from the standard design only in the section between the perfect threads and shoulder of the pin. Instead of the imperfect threads there is a zone comprised of two radii which merge tangentially at the point of maximum undercut. The minimum diameter at this point is approximately 0·02 in. less than the root diameter of the threads in a $\frac{3}{4}$-in. rod; the other sizes are dimensioned proportionally. This smoothly contoured zone accomplishes a more uniform distribution of stress in the pin. The undercut design has other practical advantages; it allows machining of the pins with less taper in the threads, and provides a space for dirt which may not have been cleaned from the threads. It is completely interchangeable with the standard sucker rod, a feature which probably explains to a large degree the favour with which it has been received.

Efficient Utilization Ensures Economy

A systematic programme for the usage of sucker rods will ensure the maintenance of repair expense from this source at a minimum level. The starting-point for such a programme is the classification of wells in accordance with the severity of operating conditions. This classification might well follow that given in Table IV which provides for light and heavy pumping wells under each of three main classes according to the degree of corrosivity. Ordinarily, new sucker rods should be purchased for use only in the heavy pumping wells of the two corrosive classes. When the sucker rods have reached their economic limit in the heavy pumping wells they are still suitable for further use in lighter pumping wells, and, consequently, new sucker rods should never be purchased for the latter type of service unless there is a lack of rods that are unfit for further use in the more severe service. Only rarely should it be necessary to use new rods in wells of the non-corrosive class.

The frequency of sucker-rod failures can be controlled to almost any degree desired by regulation of the pumping speed, length of stroke, and size of pump, and it is, therefore, important to decide when the proper economic balance between the value of the extra oil produced and the cost of the consequent increased well repairs has been attained. In corrosive service it is quite generally uneconomical to operate wells in such a manner that the load on the sucker rods exceeds 30,000 lb. per sq. in.

It is frequently difficult to decide when a string of sucker rods has reached its economic limit. Conditions do not remain constant in a well or field over extended periods, and this complicates the evaluation of sucker-rod service. Despite the numerous variables which influence sucker-rod performance, the study [7] of the service histories of a large number of strings indicates that the frequency of failures tends to follow a general law from which it is possible to derive a formula for determining when the economic limit has been reached. This formula is as follows:

$$N = \frac{C - C_s}{C_r(m-1)}, \tag{3}$$

in which

N = number of failure when cost is a minimum,
C = cost of sucker rods,
C_s = salvage value of rods,
C_r = average cost of a sucker-rod failure,
m = slope of the curve giving the relation of the number of failure to the time at which failure occurred when plotted in log-log scale.

The application of principles of engineering dictates the use of graduated strings of sucker rods where the pumping loads are heavy. Ordinarily, only $\frac{3}{4}$-in. and $\frac{7}{8}$-in. rods are used in graduated strings, since there is but little advantage to be gained by using $\frac{5}{8}$-in. rods at the bottom of such strings. On the other hand, if the pumping rate is high or the friction in the plunger is considerable, the $\frac{5}{8}$-in. rods are not rigid enough to resist buckling. Occasionally it is necessary to use a top section of 1-in. sucker rods where loads are unusually high. Generally, it is preferable to proportion graduated sucker-rod strings so that the maximum unit stress will be the same for each size of rod. Because of the elastic nature of a string of sucker rods the maximum load occurs near the middle of the upstroke rather than at the point of maximum acceleration. Under this condition the length of the larger size of rods, expressed in feet, should be one-eighth of the maximum load for graduated strings of $\frac{7}{8}$-in. and $\frac{3}{4}$-in. sucker rods, and one-fifth of the maximum load for graduated strings of $\frac{3}{4}$-in. and $\frac{5}{8}$-in. sucker rods [7]. It is always desirable to determine the maximum load with a dynamometer rather than to calculate it, since calculated values are generally higher than the measured loads. At faster pumping rates this variation is quite likely to be considerable, especially if an appreciable amount of gas is being produced along with the oil.

Combination strings of two types of sucker rods can be used with economy where corrosion and hydrogen sulphide embrittlement are severe. Except for unusual cases, about 75% of all failures occur in the top 1,000 ft. of the strings where the loads are greatest. Normally, it will suffice if only these sections are composed of the more expensive types recommended for corrosive service. A word of caution regarding the use of the low-carbon, alloy steel rods should be inserted here. Because of their low strength they are easily bent, and if $\frac{3}{4}$-in. rods are used in 3-in. tubing a failure is almost certain to bend several of the rods in the section of the string which is below the failure, and these bent rods will then fail within a short time.

Careful Handling Is Important

Much of the economy brought about by a careful selection of sucker rods can be rendered ineffective through careless handling. Fortunately, it is not difficult to recognize this condition when it exists; if the proportion of pin failures and unscrew jobs combined exceeds 25% of the total failures, it is nearly always a definite indication of poor field practice. The only exception is for heavy pumping wells when there is practically no corrosion, for in the absence of corrosion the pin is the weakest part of a sucker rod in fatigue. If joint failures are to be kept at the minimum, it is essential that they be made up with enough torque to prevent unseating at the shoulder by the pumping load, since unseating is the beginning of an eventual pin failure. Hammering of boxes or couplings to loosen the joint is another malpractice that will certainly cause an excessive number of joint failures. Snap-type sucker-rod wrenches will provide enough make-up torque to prevent unseating and make it unnecessary to loosen the joints by hammering. Sucker-rod joints are machined within tolerances [1, 1931] which class them as precision fits of the finest commercial quality, so that absence of foreign matter in the threads is necessary for perfect make-up.

Care in transportation, storage, and usage is especially important for the low-carbon steel rods because, as pointed out previously, they are easily bent, and dropping a rod

FIG. 4. Corrosion fatigue failure in a sucker rod which originated at the base of a small corrosion pit

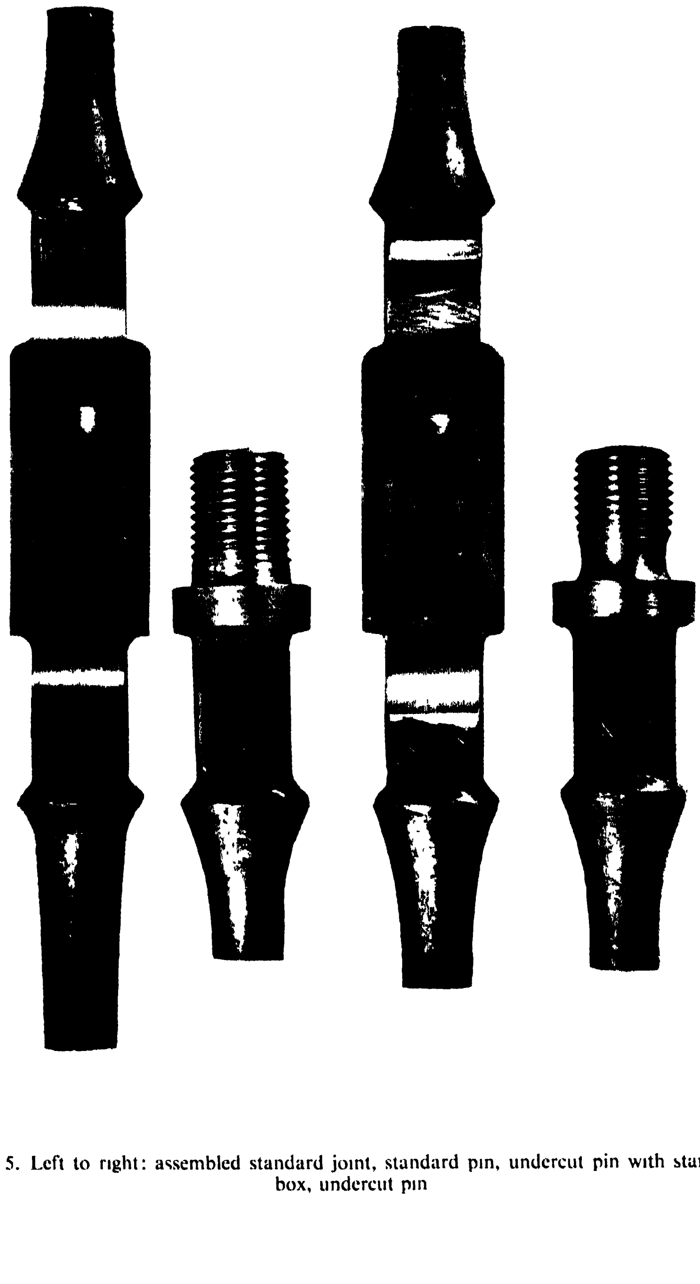

FIG. 5. Left to right: assembled standard joint, standard pin, undercut pin with standard box, undercut pin

or a bundle of rods or slamming on an elevator is more than sufficient to damage them enough to cause failure.

The following precautions will ensure satisfactory practice and absence of unnecessary failures from sources other than those induced by actual service conditions [2, 1931]:

1. Do not allow rods to drop or to be thrown during handling.
2. Always provide enough support during transportation and storage to prevent sagging or bending.
3. Do not store rods directly on the ground or on a platform; use supports to allow drainage.
4. Store rods in layers only one bundle thick.
5. Store rods under cover if possible.
6. Do not store rods without thread protectors.
7. Do not allow rods to drag while being trucked.
8. Do not hammer or chop fastenings from the bundles.
9. Do not remove thread protectors by hammering; unscrew them.
10. Do not remove thread protectors until ready to make up the joint.
11. Tail new rods into the derrick singly.
12. Clean the threads before making up a joint.
13. Do not force a joint together; unscrew it and clean the threads.
14. Use snap sucker-rod wrenches with handles at least 18 in. long.
15. Do not slam the elevator on a rod; place it on.
16. Do not hammer a joint to loosen it; use longer wrenches.
17. Pull the entire string for examination when replacing a broken rod.
18. Replace all bent or damaged rods.
19. Do not run the string back into the well without tightening the middle joints in the stands.
20. Use a sucker-rod hanger.
21. Do not let the ends drag when it is necessary to tail the rods.

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SECTION 10

SAMPLING, CORING, AND BORE-HOLE SURVEYING

THE INTERPRETATION OF CORE EVIDENCE

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INTRODUCTION

1. The interpretation of all the evidence provided by cores from drilling wells is probably one of the most important as well as one of the most difficult of the tasks which fall to the lot of the oilfield geologist or engineer. This is particularly the case where a well is being drilled in a new and unproven area ('wild-catting'), since the choice of the correct depth at which to set casing may depend on a right estimation of the worth of a sand, and an error of judgement may have very unfortunate consequences. The operator cannot be certain that even a rich oil sand will give a show of oil on the mud ditch, since the pressure in the sand may not be sufficient to overcome the pressure due to the weight of the drilling mud, especially if the well be a deep one. Neither can he depend on the cores of a sand showing unmistakable signs of oil, if the oil is a light one and therefore evaporates quickly. Moreover, the best parts of a sand may be those which are the softest and cannot be retained in a core-barrel, the parts recovered being those which are harder and contain less oil. There are, in fact, a large number of pitfalls for the geologist or engineer when dealing with coring wells, and the subject is not one about which a great deal has been written. The writer has had a fair amount of experience with coring in more than one field, and is impressed with the lack of knowledge displayed by most drillers and many engineers as to the best means of evaluating the evidence provided by cores.

2. Now this evidence may be divided into four classes, each of which will be studied in turn:

(i) *Lithological:*

- (*a*) General—type of rock, general texture, and appearance.
- (*b*) Particular—(minute characteristics, marker beds, &c.).

(ii) *Stratigraphical:*

- (*a*) Palaeontological evidence.
- (*b*) Petrological evidence—mainly by heavy mineral separation.

(iii) *Structural:*

- (*a*) General evidence as to amount of dip. Presence or absence of false bedding.
- (*b*) Signs of faulting, crushing, or contortion.
- (*c*) Presence or absence of unconformities.

(iv) *Physical Characteristics:*

- (*a*) Porosity and permeability.
- (*b*) Hardness.
- (*c*) Size of grains—in the case of a sandstone.
- (*d*) Fluid content (oil, water, and gas).

3. This article is concerned only with the interpretation of the various items of evidence detailed above, and no attempt will be made to describe in detail the methods of obtaining them.

4. What follows refers mainly to coring in rotary drilled wells, but a few notes on coring in cable-tool wells will be found at the end of the article. These are followed by a list of references which will be found useful for obtaining information concerning methods of determination of porosity, permeability, &c., and details of some core studies in the United States.

IMPORTANCE OF GOOD CORE RECOVERY

5. Before dealing with these various items of evidence to be obtained from cores, it would be well to emphasize that one of the essentials in securing a complete knowledge of an underground range of rocks by coring is that core recovery should be good. The writer's conception of 'good' core recovery is 75% or over; between 55% and 75% may be described as moderate, and under 55% as poor.

6. With poor core recovery and a formation of an alternating type it is often difficult to obtain a true picture of the lithology. Moreover, it is possible that in some instances an error of 20 ft. or so may arise in the recorded depth of a given stratum. This is particularly the case where the formation is hard, and if the core-catcher fails to hold the core, a cylinder of rock is left standing up in the hole. In the next run the core-barrel may go clean over the cylinder, core a further few feet, and then again leave the core in the hole. In one instance that the writer knows of where a core-barrel 21 ft. long was being used, 10 ft. was cored and the recovery was nil. Another 8 ft. was then cored, and recovery was again nil. In the third run 3 ft. was cored, and on pulling out 2 ft. of core was found in the barrel. It was inferred from a Schlumberger electrical survey that this 2 ft. was the top of the first core and not a part of the third core taken. Evidently the cores had been left standing up in the hole, and each time the barrel went neatly over the whole cylinder before starting to take the next core. In the third run the barrel (21 ft. long) must have been full, but on pulling out the bottom 19 ft. again slipped through the core-catcher and only the topmost 2 ft. were retained.

7. Such errors may not be of great importance in the majority of cases, especially if an electrical survey is made, but in some fields where water sands lie in close proximity to oil sands an error of 20 ft. may have regrettable results.

8. In deciding on the probable lithology of cored ranges in which core recovery was poor, the driller can often render valuable help. Soft and medium hard sands usually core easily and quickly, shales more slowly, while hard sandstones and limestones core very slowly and irregularly and the core-bit tends to 'chatter' on bottom. By consulting the driller as to the nature of the coring at various depths, it may thus be possible to gain some idea of the lithology of lost cores. Moreover, unless a very soft sand is being cored, it is usually the lowest part of a core which is lost, due to failure of the core-catcher, but two points are of importance in this connexion:

(*a*) If the core is found to be burnt in the core-head and core recovery is poor, the driller must always be consulted as to which part of the core he considers was recovered. If the top part cored very easily like soft sand, it may have been washed away by the mud circulation, and then when a change of formation occurred the core started to enter

the barrel. In this case the recovered core represents the bottom part of the cored range. If, on the other hand, the whole rock cored slowly, it may be that the core-head was cutting slightly too big a core to enter the inner barrel easily, and after a few feet the core became jammed and could no longer slide up the barrel. In this case the remainder of the core taken will be merely ground up, and the recovered core will be the top part of the cored range.

(*b*) If for any reason the core-barrel had to be lifted off bottom while coring, the core already taken may slip through the core-catcher and be ground up during further coring. In this case, of course, the recovered core represents the lowest portion of the cored range.

LITHOLOGICAL EVIDENCE

9. The general lithological type of the rock recovered in a core can be determined very quickly by inspection. Since, however, in the case of rotary wells drilled with mud fluid the core comes to the surface coated with a layer of mud, it is of course necessary that the core should be thoroughly washed so that none of its characteristics are masked in any way. Care must be taken that before any washing is done careful examination be made for signs of oil, gas, and water in the porous parts of the core, and if any oil and gas are present, suitable samples of unwashed core should be removed in airtight containers to the laboratory where tests (to be described later) are undertaken.

10. After a general examination to determine the nature of the core (i.e. to see whether it consists of limestone, sandstone, shale, &c., or a combination of two or more of these), a much more detailed examination should be made for fossils, plant remains, and any possible distinctive beds which may serve as marker horizons. Such marker beds may occur as

(*a*) thin, very fossiliferous bands;
(*b*) thin, very hard sandstones ('shells');
(*c*) conglomerate beds or breccias;
(*d*) unusually fine or coarse sandstones, or sandstones of a particular colour;
(*e*) a band of distinctive rock such as (for example) a limestone, a coal seam, a bentonite [16, 1931], or a coarse grit.

11. In many fields where lateral variation is very prevalent such thin beds might be useless as marker horizons, and the operator has then to fall back on broader groups for establishing his general correlation. The presence of such broad groups is of course most useful even when the thinner marker horizons are present. Moreover, they are more easily revealed by coring, since their identification depends less on good core recovery. Care must be taken in using as marker beds thin bands of great hardness and of no other special characteristics. The hardness often varies greatly from place to place, and although the writer knows of certain bands which retain a remarkable degree of hardness over a wide area, there appear to be many cases where this does not occur.

STRATIGRAPHICAL EVIDENCE

12. After examination of a core for lithology—usually and preferably at the well immediately after removal from the core-barrel—the core should be sent to the office or laboratory and examined in greater detail for fossil evidence. If the evidence is likely to be of considerable value, it should be obtained by

(*a*) ordinary examination by naked-eye and hand lens, and also
(*b*) microscopical examination after preparation of thin sections.

13. A further refinement is the preparation, from cores of sands, sandstones, or limestones, of heavy mineral residues and their examination under the microscope. Correlations by such means may in certain cases be of much value in elucidating minor features of structure—particularly in faulted fields—and in some fields heavy minerals are highly important for establishing major correlations.

14. In an established field, where the general correlation is well known, refinements such as the above are rarely necessary, and detailed examination of cores for fossils or heavy minerals may in such cases be omitted. It is usually desirable, however, that the cores should be stored in a safe place, so that if any questions later arise as to the correlation of the field, reference may again be made to the cores and a more detailed study carried out.

STRUCTURAL EVIDENCE

General Evidence as to Amount of Dip

15. This is obtained quite easily after carefully washing the core and selecting those parts of it which show a good dip. Some rocks which at first sight show no dip—e.g. mudstones—will often crack along lines parallel to the dip if set aside and allowed to dry for a time. In others, indications of bedding may be obtained by a minute examination.

16. In order to obtain the true dip from observations of the dip in the cores, the following simple rules must be observed:

(*a*) If the well is deviating directly down-dip, the true dip is equivalent to the measured dip *minus* the amount of deviation.
(*b*) If the well is deviating directly up-dip, the true dip is equivalent to the measured dip *plus* the amount of deviation.
(*c*) If the well is deviating in a direction intermediate between that of the true dip and the direction of strike, the true dip is the measured dip plus or minus a proportion of the amount of deviation, depending on the amount of departure of the direction of deviation from that of the true dip.

Where the direction of dip is unknown, it is not possible to obtain more than an approximate idea of its real amount unless the well is vertical or nearly vertical. In such cases it may be worth going to the trouble of orienting the drill-pipe out of the hole after taking a core in order to discover the approximate direction of dip [9, 1930]. A laboratory service for the determination of direction of dip is now given by the Sperry-Sun Well Surveying Co. of Philadelphia, Pa.

False Bedding

17. Particular care must be taken that the dip as measured in the core is a representative one and not affected by false bedding. The latter usually occurs most markedly in sandstones, but may also be present in alternations of sand and shale, the sand streaks showing a wavy dip, which in parts may be far from parallel to the real dip of the strata. As

a rule it is best to ignore entirely any dips suspected of being influenced by false bedding and consider only those which are almost certainly not so influenced. Probably the best type of rock for exhibiting dips is a compact shale with thin streaks of sand.

Faulting

18. The presence of faulting may be shown in cores by

(*a*) Dips considerably higher than normal; the dip may in some cases be contorted and the rock crushed.

(*b*) A known range may be eliminated, in the case of a fault of the normal type, or repeated in the case of a fault of the reversed type.

(*c*) The presence of calcite or gypsum veins, mud veins, slickensided surfaces, or broken and crushed rock. The latter is often very soft and is easy to confuse with cavings.

The extent of a fault zone in a well, as shown by steep dips or any of the other signs mentioned above, may be very variable. On the one hand, the fault may cause very little disturbance in its immediate vicinity and have no effect on the rocks a few feet above and below it; or, on the other hand, the zone of disturbance may extend to scores or even hundreds of feet on either side of the plane of faulting. Moreover, a fault which at the surface is a small feature and not easily recognized may, underground, be entirely different and show a wide zone of fracturing and disturbed strata. The reverse may also be the case. Frequently, also, a fault may be cored in a well which has no counterpart on the surface, or conversely, a fault at the surface may die out underground.

19. With such variations it is important to keep an open mind when a particular fault known at the surface is thought to pass through a well and an attempt is being made to core it. With poor core recovery it may be missed entirely, or if the fault zone is a wide one, it is very difficult to say exactly where the fault 'plane' occurs. If the well happens to cross the fault at a place where, for example, an incompetent shale bed is faulted against a more massive type of rock such as a sandstone, the shale may be crushed and contorted for perhaps a hundred feet on one side of the fault, whereas on the other side the sandstone may be quite unaffected and show no abnormal dips. In such cases, of course, the fault plane is not in the middle of the crushed zone or at the end of it away from the sandstone, but at the junction between the crushed shale and the sandstone.

20. Where faulting is present and wells on opposite sides of the fault have been cored to some extent, the presence of marker beds is of course of much value, not only for determining the throw of the fault, but also for indicating, in the absence of other evidence, that faulting is present.

Unconformities

21. Coring may also indicate the presence of unconformities by showing a progressive thinning or thickening of a stratigraphical series from well to well, or by indicating that parts of the series are missing in certain portions of the field. The sudden incoming of conglomerates or breccias is often an indication of the presence of an unconformity.

PHYSICAL CHARACTERISTICS

(i) Porosity and Permeability

22. These characteristics are of importance in the case of sands, sandstones, limestones, or any other potentially productive rocks encountered in a well, especially when coring through the range known to be that from which the well will later produce oil. Methods of measuring these factors have been described in various papers—for example, 'Measurement of Permeability of Porous Media', by R. D. Wyckoff, M. G. Botset, M. Muskat, and D. W. Reed (*Bull. A.A.P.G.* **18**, 2, 161–90 (1934), and 'Physical Analysis of Oilsands', by P. G. Nutting (*Bull. A.A.P.G.* **14**, 10, 1337–49 (1930).

23. Melcher found that in the Burbank Field of Oklahoma there was a definite relationship between porosity and productions of wells, irrespective of position on the structure. In the Hickman Sand a well which recorded 25% porosity gave twice the production of another with only 21% porosity, and in general small increases in porosity were found to be of much importance. Furthermore, there appeared to be for most sands a lower limit of porosity below which no production was obtained. This, for the Bartlesville Sand, was found by Melcher to be 12% and for the Hickman Sand 13%.

24. Nowadays the factor of permeability is thought to be of more importance than porosity. In many cases a highly permeable sand is also highly porous, but this relationship does not necessarily hold good. It is probable that Melcher was dealing more with permeability than with porosity, and that the barrenness of the sands he examined and found to have very low porosities was really due to extremely low permeability [14, 1932].

25. So far not a great deal is known about the permeabilities of reservoir rocks and their relation to productivity, but it is obvious that a correct knowledge of permeability plays an important part when deciding on the correct spacing for wells. It is important when determining the initial pressure at which to start repressuring operations with air or gas, and it is also of use, when coring in new territory, for deciding whether or not a sandstone which may give slight signs of oil is likely to prove capable of yielding commercial quantities of oil and gas.

26. In the case of limestone fields, and indeed in many sandstone fields as well, a factor of much more importance than local permeability is the degree of fissuring which the rock has undergone—or in other words, the *regional* permeability of the reservoir rock. This is unfortunately difficult to measure, since it will be very rare indeed that fissures will be actually cored on a large scale. Where such fissuring is present to any extent, the permeability of core samples of limestone or sandstone is a factor of very little importance, and may even be completely misleading.

27. In fields where the producing horizon is a soft, easily flowing sand, another factor of much importance in controlling the rate of production may be the extent to which fissures are formed by sand flowing towards the well with the oil and being produced with the latter. This again cannot, of course, be measured in core samples.

(ii) Hardness

28. Hardness in the case of sands and sandstones is usually bound up with permeability, since the harder a sandstone the more highly cemented it is and the less is its permeability. Very hard beds usually neither contain much oil nor show much oil in a core sample, and therefore they rarely present a problem in interpretation of evidence.

(iii) Size of Grains (in the case of Sandstones)

29. This factor is of importance when estimating the total fluid content of a reservoir and the maximum recovery of oil likely to be obtainable. The best percentage recoveries

should be obtained with coarse, even-grained sands and the poorest recoveries with very mixed sands. In the latter case the area of the surfaces of the sand grains per unit volume of sand is much greater than in the case of a coarse, even-grained sand, and the amount of oil which will be left adhering to the sand grains, even after maximum possible extraction, is relatively very large.

30. It is useful, therefore, to break down a sandstone into its component sand grains, separate these into various sizes by sieving, and weigh each separate component. The result can then be expressed graphically and easily compared with other samples [15, 1930].

(iv) Fluid Content (Oil, Water, and Gas)

31. The fluid content of a core is perhaps the most difficult factor of all to evaluate in commercial terms. It is simple enough to say whether a given core sample does or does not contain oil or gas; it is less simple, as a rule, to say whether or not it contains water; but it is often a matter of great difficulty to say whether oil is present in commercial quantities and the approximate proportion of water, if any, which the sand will produce in the particular well being drilled.

32. The time when such information is of the utmost importance is when drilling and coring in unknown territory, where the proper depth for a water shut-off can only be determined by inspection and evaluation of cores. Of recent years the development of formation testers attached to the drill-pipe has made so much progress that decisions as to cementing depth can now be made much more easily than before, but there still remain fields where the use of a formation tester has proved to be either unsatisfactory or even impossible, for a variety of reasons. In such cases a right decision as to cementing depth depends almost entirely on the skill of the operator in interpreting his core evidence. (The writer is not concerned in this article with the various electrical devices now available for detecting the presence of oil and gas sands).

33. The amount of free oil which a core will show when brought to the surface depends on a large number of factors, the chief of which are as follows:

(*a*) The nature of the oil—its colour, gravity, and petrol content.
(*b*) The depth of the hole and the bottom-hole pressure.
(*c*) The amount of gas originally dissolved in the oil.
(*d*) The nature of the rock.
(*e*) The quality of the mud.
(*f*) The position of the well on the structure—particularly with relation to the oil-water margin.
(*g*) The time that elapses after bringing the core to the surface till it is inspected by the geologist or engineer in charge.

To take each of these points in detail:

34. **The Nature of the Oil.** Other things being equal, the lighter the colour of the oil, and the higher its petrol content, the poorer will the oil show up in core samples. A small amount of a relatively heavy, dark, asphalt-base oil can give a magnificent show in a core, whereas gassy paraffin-base oil, light in colour and gravity, may hardly show up at all. With a very light oil a really good odour may indicate a highly productive sand.

35. **The Depth of the Hole and the Bottom-hole Pressure.** Generally speaking, the greater the depth of the hole—and therefore the pressure in the oil sand—the greater the chances of a core losing its oil by evaporation on the way to the surface. Underground, the oil with its occluded gas is held in the pore spaces of the sand under pressure, but when a cylinder of the sand is cored and brought to the surface the pressure is gradually released, with the result that a large part of the oil and most of the gas gradually escape.

36. **The Amount of Gas originally dissolved in the Oil.** The greater the amount of gas in the oil at the reservoir pressure, the greater will be the loss of oil and gas on the way up the hole, and the gas in escaping will carry the lighter fractions away with it.

37. **The Nature of the Rock.** A soft porous sand will of course show much more oil than a hard, well-cemented sandstone, and a massive limestone or dolomite—from which production is obtained out of crevices fed by minute pore spaces—may show no oil at all.

38. **The Quality of the Mud.** This is of importance from the point of view of the amount of 'free' water which the mud contains. In rotary wells using a mud-circulating system cores are bathed in mud in the process of cutting, and they absorb a certain amount of water from this mud. This is a familiar feature of most cores seen by the writer, and it is mentioned by C. R. Fettke in connexion with the cores of the Venango Sand of Oil City, Pa., where nine samples were found to contain water to the extent of 37% of their pore space although the sand on production yielded no water [7, 1926].

39. Each sand appears to show a certain minimum percentage of water in cores (provided its permeability does not vary greatly), although the sand is really 'dry', and this minimum value can only be determined by experiment. A higher percentage of water than this minimum may indicate that the sand is water-bearing.

40. When coring with a mud from which water easily separates out, more water will be absorbed by the cores than when using a better type of mud, and hence when coring oil sands, for this reason as well as for many others, a good mud containing as little 'free' water as possible should be employed.

41. **The Position of the Well on the Structure—particularly with relation to the oil-water Margin..** In this connexion we may assume the usual relationship for the average anticlinal fold—gas or gassy oil at the crest, less gassy oil farther down the structure, oil accompanied by water still farther down, and finally water only on the flanks.

(*a*) In the crestal portions of the structure where oil is often accompanied by gas only, the cores of a good sand should certainly show 'liveliness'. Gas will often bubble out of the pores of the sand and carry small quantities of oil with it. Sometimes the oil is visible merely in the form of a slight iridescence, but occasionally it may ooze out of the core in fair quantity. The mud coating should also show unmistakable signs of fresh oil. The core should smell strongly when a fresh surface is exposed by breaking the core, but the smell will often disappear very quickly. Fresh surfaces when first exposed may have a wet appearance, if the oil is a very light one, but the oil will evaporate quickly and leave the sand dry (this distinguishes it from a water-bearing core where the surface will not dry quickly). In the case of a heavier oil the presence of the oil should be much more easily seen—both in the mud surrounding the core and also along the bedding planes of the rock.

(*b*) Farther down the structure cores of a sand may show many of the characteristics of the foregoing and may *appear* to contain quite as much gas. Much depends on the colour and gravity of the oil—a light oil may give merely a good odour, and of oil itself there may be very little sign.

In the case of a heavier oil which has suffered less evaporation, the oil may ooze out of the core as it is extracted from the core-barrel.

(c) At the edge of the pool, where oil is accompanied by water, the appearance of cores is often deceptive, and therefore it is impossible to be too careful in examining such cores. As a rule they will show none of the liveliness of a core taken higher up the structure, a good smell will in many cases be absent or nearly absent, and patches of water may be present along the bedding planes. Beyond its oil-water margin, or in a position where oil is not present in commercial quantities, the sand often shows a surprising amount of oil in a core sample [4, 1933]. But this oil is usually devoid of gas, occurs as irregular patches surrounded by sand with a damp appearance, and is, as a rule (though not always), absent except along the bedding planes. When broken along these bedding planes the cores often show quite unmistakable signs of water, and also a few globules of oil, but the presence of the latter should not be allowed to blind the operator to the real nature of the sand. The writer has observed that many such cores are softer than in the case of the same sand higher up the structure.

(d) Still farther down the structure, well beyond the oil-water margin, cores, as a rule, reveal their identity without trouble. The rock will look definitely wet, and even small globules of oil will be absent. The writer, however, has been struck by a few cases of a sand containing gas as well as water beyond its oil-water margin (and this also appears to be the case in the Woodbine Sand of East Texas). The gas may give an excellent odour in the cores, but the presence of water will in most cases be unmistakable, and the complete absence of any sign of oil will convince the operator of the worthlessness of the sand from the point of view of oil production.

42. **The Time that elapses after bringing the Core to the Surface till it is inspected by the Geologist or Engineer in charge.** This is, of course, a very important factor. It is essential that cores should be examined by the geologist or engineer personally as soon as possible after they have been brought to the surface, since with light oils evaporation—already well started—will soon rob the cores of nearly all signs of gas and oil. Wherever possible, therefore, the geologist or other person responsible should be on the derrick floor when the core-barrel is brought to the surface.

43. One point, however, is of importance in this connexion. It is often unwise to examine cores of a sand containing a light oil by artificial light after dark. Even with very strong artificial light a light-coloured oil is extremely difficult to see, and may indeed be missed altogether. It is often wise, therefore, in the case of cores taken after dark, to seal the ends of the core-barrel with strong airtight screw caps and inspect the cores in daylight.

44. A further point of some importance is that a core of oil sand which has been lightly washed and allowed to dry will often show a darker oil-staining which was not visible when the core was fresh. This feature may be most useful when dealing with light oils which merely give a strong odour in a core and very slight further signs of oil. In such cases, if the lighter fractions are allowed to evaporate, the heavier ones which are left may serve to stain the core a slightly darker colour than before, and convince the operator that he is dealing with an oil sand and not with a gas sand. If such staining does not occur, and if signs of oil in the fresh core were completely absent, the suspicion is very strong that the sand is either barren or, if any gas showed up, is a gas sand devoid of oil in this locality. The fluorescence obtained with ultra-violet light (mentioned below) is also useful in this respect.

45. **Laboratory Tests of Core Samples.** It was mentioned at the beginning of this article that as soon as a core is recognized as an oil sand parts of it should be removed immediately, without washing, to the laboratory in an airtight container. The first tests to be carried out should, of course, be those for determining the quantity of oil and water present. Later on these can be followed up by tests of porosity, permeability, size of sand grains, &c.

46. (a) The test for oil content is made by taking a known weight of core—the inner portion away from the mud sheath—and extracting the oil with a known amount of light petrol or ether. The weight of oil extracted can be expressed either as a percentage of the weight of the core sample or as percentage saturation after the porosity has been determined.

47. The water content can be found by means of the well-known Dean and Stark apparatus (as used for estimating the water content of coals), and the result expressed in the same way as the oil content.

48. (b) If the oil content of the core is questionable, the acetone test can be used. A little of the pulverized sand is added to acetone in a test-tube and then followed by water. If oil is present a milkiness appears. This test may be useful in the case of very light oils, but care must be taken in applying the result of the test, for it will give a show with a minute quantity of oil and may be misleading.

49. (c) The presence of water can be ascertained by use of potassium permanganate, which is soluble in water but not in oil. Since, however, nearly all cores absorb water from the drilling mud this test is not conclusive. It should in any case be used only on the innermost parts of the core.

50. (d) Certain yellow, oil-soluble dies which are insoluble in water may be useful for showing whether oil is present or not.

51. (e) The core of a sand containing even a little oil should show iridescence when immersed in water.

52. (f) Where any doubt exists as to whether or not the oil in a core is primary, the test of fluorescence obtained with ultra-violet light is useful [1, 1933]. A crude oil gives an entirely different type of fluorescence from a refined oil, so that contamination with kerosene or lubricating oil can easily be spotted. The method is also useful for determining whether a sand with a good odour contains a light oil or merely dry gas.

53. Probably the most useful of the above tests, taken in conjunction with a careful examination on the derrick floor, is the first, but only after a number of these tests have been correlated with actual results in wells in terms of oil production. Careful work on an established field may be successful in establishing working rules for use in future wells, by which a certain minimum percentage of oil in a core sample will indicate a sand worth testing, and a certain maximum percentage of water will indicate a 'dry' sand. It is impossible to give empirical rules for these tests, and it would be unwise to apply to one field the figures obtained from another field. Each field must be considered in this respect as a law unto itself until it can be proved that it is similar to some other field. Moreover, cores of different sands in the same field may give different results, especially if there are variations in the colour and gravity of the oil.

CORING IN CABLE-TOOL WELLS

54. All the foregoing applies to rotary wells drilled with a mud-circulating system. It applies also in large degree to

wells drilled by the cable-tool system in which the long column of mud is replaced by a small amount of 'drilling water'. Several tools are now on the market which provide useful cores in cable-tool wells, and only a few points need be added in connexion with the interpretation of the evidence they provide:

(*a*) In view of the small amount of fluid usually in the hole when drilling with cable tools, a little caving is often very difficult to avoid, especially in soft formations, and therefore the upper part of the core will almost invariably consist of cavings.

(*b*) Evidence of structure provided by a cable-tool core is not as a rule so reliable as in the case of rotary cores. A certain amount of distortion often takes place at the edges of the cable-tool core, and in these cases only the inner parts should be considered for dip evidence.

(*c*) Absorption of water is not so common as in the case of cores from rotary wells, and with high-pressure sands may be entirely absent. With low-pressure sands slight absorption of the drilling water may take place.

55. In conclusion it must be emphasized that all the above tests are merely an aid to the estimation of the value of cores and by no means fool-proof. No method has yet been evolved by which the geologist can predict exactly what a sand is worth from an inspection of samples taken from the core-barrel. At present he can only form an opinion, based on hard-won experience, and much painstaking research will be necessary before it will be possible, from mere core inspection and examination, to evaluate a sand in terms of oil production.

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BOTTOM-HOLE PRESSURE MEASUREMENT

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THE more efficient methods of oil recovery practised in recent years, and the adoption of scientific unit development of single structures and of proration of individual properties in cases where the vagaries of multi-ownership have proved a stumbling-block to unit development, necessitate an intimate knowledge of underground physical conditions. More particularly, static and flowing pressures at depth in wells have proved to be of basic importance and to have a wide practical application to the solution of oil development and production problems. Since these data cannot be obtained by surface observation alone, a new technique has been developed, known as 'bottom-hole pressure measurement'.

Method of Determining Bottom-hole Pressures

Three general methods have been evolved for measuring the pressure at the bottom of a bore hole: (*a*) lowering a pressure-sensitive element and recording electrically at the surface, (*b*) transmitting the pressure to surface through a fluid column of known density, and (*c*) lowering a self-recording type of pressure-sensitive element and observing the record after the instrument has been brought to surface.

The electrical method of measurement is not extensively used in practice. The initial cost of an insulated cable capable of withstanding the effects of gas, oil, and formation water under pressure is considerable; furthermore, the operation of lowering and raising a cable of the necessary weight and diameter requires relatively heavy equipment and is liable to prove difficult in high-pressure flowing wells.

The most common method of transmitting the pressure at the bottom of a hole to surface is to insert small diameter tubing and to fill the tubing with gas. The pressure at surface is then measured with an ordinary bourdon tube type of gauge, or with a dead-weight tester, and the pressure at the bottom calculated from the formula

$$\int_{P_1}^{P_2} \frac{dp}{p} = \int_0^N \frac{WS}{14{\cdot}7\times 144D}\,dx,$$

or

$$\log_e P_2 = \log_e P_1 + \frac{WSN}{2{,}118D},$$

where P_1 is the absolute pressure at the top of the column, P_2 the absolute pressure at the bottom of the column, W the weight of 1 cu. ft. of air at 14·7 lb. per sq. in. and average well temperature, S the specific gravity of the gas compared with air, D the compressibility divergence factor of the gas at pressure P, and N the depth to which the tubing is inserted.

This form of transmitting pressure to surface obviously cannot be used in flowing wells, and in view of the necessity of inserting tubing is not suitable for routine use in static wells. A modification of the method has, however, been devised by the engineers of the Gulf Production Company, U.S.A., and has been used in the East Texas field. The apparatus is described by Gill in the *Oil Weekly* of 4 April 1932, and in the *Transactions* of the Petroleum Division of Amer. Inst. Mining and Metallurgical Engrs., 1933 [1]; it consists of sections of small-diameter seamless steel tubing welded into a continuous flexible tube. The bottom end carries sufficient weight to prevent the tubing coiling in the hole, a recording thermometer, and two check valves to prevent oil from entering the tubing. The tubing is coiled in a single layer on a large-diameter drum, which is mounted on a truck and driven by the truck engine. Connexion is made to the upper end of the tubing through a stuffing box, thence to a gas manifold to which a pressure gauge is connected. Hydrogen is used as the gas medium on account of its mobility and low specific gravity, and is carried in cylinders under high pressure attached to the gas manifold. A pressure is measured by merely admitting hydrogen until the tubing pressure is definitely above that to be measured, allowing equilibrium to be reached, and then observing the surface pressure gauge.

The use of the apparatus is not recommended, as apart from the high initial cost it has the following disadvantages. (*a*) the welded joints are liable to break as, in order to allow the tubing to pass through a gland at the well head, it is not permissible to increase the diameter at the joints; (*b*) mill scale formed in drawn tubing is difficult to remove and is liable to cause blockage; (*c*) the apparatus is bulky on account of the large-diameter drum required to eliminate bending stress; and (*d*) when used for continuous readings errors are liable, due to lag of pressure adjustment in the long length of capillary tubing.

The most common type of bottom-hole pressure gauge now in use is that embodying the principle of the pressure-sensitive element with self-contained recording device. Rapid advance in instrumental design has been made in recent years with this type of gauge, and it is now employed as a matter of routine by most of the major oil companies. An essential feature of design is that it should be of small diameter (less than 2 in.), streamline in shape so as not to cause obstruction in a flowing well, and of sufficiently light construction to be lowered and raised in a well on a single-stranded line such as a piano wire.

Various types of pressure-sensitive elements have been designed, the principle on which they operate being either (*a*) flexure of a metallic element, such as a bourdon tube, collapsible sylphon tube, &c.; (*b*) compression or extension of a spring by a sliding piston, or (*c*) compression of a volume of gas. Most pressure-sensitive elements are affected by temperature, and it is therefore advisable to measure the bottom-hole temperature and to calibrate the instrument at the surface at the measured temperature. The usual method of calibrating is to test directly against a dead-weight tester.

The following description classifies the better known and more reliable bottom-hole pressure gauges in accordance with the principle on which they operate. Its chief purpose is to give the essential features of the different gauges, the method of their operation, their defects, accuracy, and sensitivity, in order to place the reader in a position to judge for himself the type of gauge to purchase for any particular purpose. Attention is not therefore given to mechanical detail, and Fig. 1 is only intended to assist in a better understanding of and to shorten the written description.

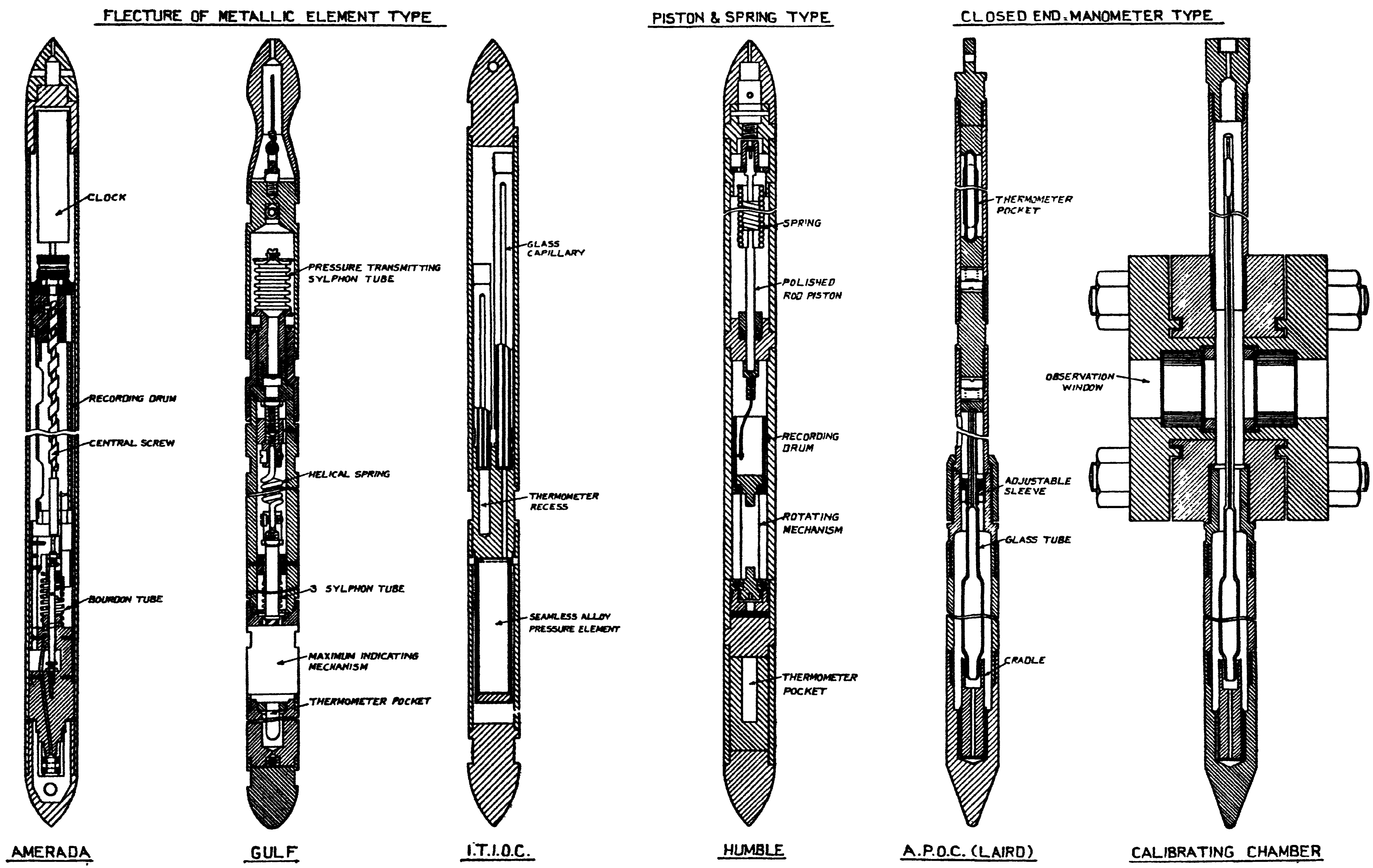

FIG. 1. Types of bottom-hole pressure gauges.

(a) Instruments depending on Flexure of a Metallic Element.

Probably the best-known gauge of this type is the Amerada designed by the Geophysical Research Corporation, Tulsa, and extensively used in the Mid-Continent and Texas (U.S.A.). It is described by Millikan and Sidwell in the *Transactions* of the Petroleum Division of the A.I.M.M.E., 1931, and in the *Petroleum Engineer*, May 1931 [5]. The pressure element consists of a bourdon tube, fabricated into a spiral coil $\frac{7}{8}$ in. in diameter and 7 in. in length and fitted in a pressure-tight container.

The lower end of the tube is connected to the base of the container and the well pressure is transmitted to it through a port. The sealed upper end is attached to a shaft which in turn is attached to an arm carrying a stylus for recording on a metallic-faced paper chart. The chart is carried on a drum driven by a central screw which is operated by a specially designed clock. The power demanded of the clock is reduced to a minimum by arranging that the screw drives the chart carrier downwards so that its weight almost balances friction. The whole apparatus is carried in a pressure-tight container having an external diameter of 2 in.

The chart is 7 in. in length and $2\frac{7}{8}$ in. in width. It is obvious that the instrument cannot have very great sensitivity at high pressures. For instance, at 1,000 lb. per sq. in. one-hundredth of an inch on the chart probably represents a range of 10 lb. per sq. in. The sensitivity at lower pressures may, however, be greatly increased by substituting a lower-range bourdon tube to cover the whole width of the chart.

The accuracy of the instrument depends entirely upon the helical steel tube. Errors are liable, due to hysteresis, temperature, and other effects, just as in an ordinary bourdon type of surface pressure gauge. These effects may be negligible at low pressure, but are appreciable at high pressures. For accurate work it is therefore advisable always to calibrate the instrument at the surface immediately after its withdrawal from the hole, the temperature being maintained at bottom-hole temperature. Preparation of the helical tube by submitting it to a pulsating pressure before use in an instrument might also assist in eliminating inaccuracies.

Another bottom-hole pressure gauge depending on the flexure of a metallic element has been designed by R. S. Piggot of the Gulf Research Laboratory, Pittsburgh, U.S.A., and is described by Hawthorn [2, 1933]. In this case the metallic element is a sylphon tube or 'bellows', $\frac{1}{2}$ in. in diameter and about 3 ft. in length, made of bronze for low pressures or chrome molybdenum steel for high pressures.

The lower end of the sylphon tube is attached to the body of the instrument and the upper end to a rod which passes through the tube to a recording device. The other end of the rod is in turn attached to the free end of a helical spring, the purpose of which is to hold the sylphon tube in any desired tension. Pressure applied to the sylphon tube causes it to compress downwards, moving the rod against the resistance of the helical spring. To the lower end of the rod is fixed a pin, which moves in a helically fluted tube and operates a maximum recording dial. The calibration of the sylphon tube is readily affected by corrosion or H_2S embrittlement, and consequently the crude or water from a well should not be allowed in contact with this part of the instrument. The pressure chamber is therefore filled with lubricating oil, the well pressure acting on a short upper sylphon tube which serves as a seal and pressure transmitting diaphragm.

The sylphon tube is greatly affected by temperature, and it is therefore essential to calibrate the instrument with a dead-weight tester at the bottom-hole temperature. A thermometer pocket is fitted to the instrument for this purpose. The accuracy of this type of gauge is liable to vary considerably with different instruments and depends upon the degree of perfection of the sylphon tube. The sensitivity of the gauge at low pressures may be improved by adjusting the tension of the spring to suit the range of pressure to be measured. It is doubtful, however, whether a better accuracy than 10 lb. per sq. in. can be obtained at high pressures.

A gauge depending for principle on the flexure of a metallic element of very simple construction has been designed by P. McDonald of the Indian Territory Illuminating Oil Company of Oklahoma, U.S.A. This instrument has also been described by Hawthorn in the *Oil and Gas Journal* of April 1933 [3]. The pressure element is a square section seamless alloy tube welded to the lower end of the body of the instrument and containing an invar steel rod to compensate for temperature effects. A glass capillary tube is fitted to the top of the pressure chamber and is connected with the inside by means of a drilled hole. A recess drilled in the body of the instrument, also fitted with a glass capillary tube, serves to measure differences of temperature. The whole apparatus is fitted within a pressure case $1\frac{1}{2}$ in. outside diameter and about 4 ft. in length.

Both pressure and temperature systems are filled with mercury to the top of the capillary tubes. As the instrument is lowered into a well the pressure compresses the pressure element, causing overflow of mercury, while the rise of temperature expands the mercury in the temperature recess. The mercury levels fall in the capillaries on withdrawing the instrument, and their position is noted by removing the upper end of the case. The bottom-hole pressure is determined by calibrating the pressure element with a dead-weight tester, and the temperature increase is similarly determined by direct calibration.

A feature of this type of gauge is its good sensitivity, as the pressure change can be made to cover any length of scale by merely varying the diameter of the capillary tube. One defect of the instrument is that it tends to read too high, as mercury is liable to spill over if the instrument is subjected to a sharp jerk. A cap with a small hole is fitted to the top of the tube to reduce the error due to this defect. Care in withdrawing the instrument for the first 100 ft. eliminates the error entirely in a static well, but in a flowing well the instrument is liable to be subjected to continuous jerks.

(b) Instruments depending on Compression or Tension of a Spring by a Sliding Piston.

Several gauges of this type have been designed, notably by the Anglo-Iranian Oil Company in conjunction with George Kent Ltd. of Luton, the Humble Oil Company of Texas, and the Standard Oil Company of California, but since all operate on the same principle it is only necessary to describe the construction of one of them. This type of gauge consists essentially of a piston of known diameter upon which the well pressure is exerted, a calibrated helical spring which resists the movement of the piston either by compression or tension, and a recording device.

A gauge of this type was manufactured by Kent's for the Anglo-Iranian Oil Company in 1927 and was probably the earliest specially designed bottom-hole pressure gauge. In this instrument the piston is a sliding metal to metal fit with

the case. The piston compresses a spring, the extent of compression being measured by the movement of a rod operating a maximum recording device. The accuracy of this instrument as originally designed was adversely affected by leaks past the piston, tending to exert a pressure within the pressure container and so giving low results. The form of the gauge has therefore been modified; the later design is similar in all essential features to the Humble Oil Company gauge, which is very widely used in the United States.

The piston or plunger of this instrument is a polished rod of stainless steel 7 in. long and ¼ in. diameter. The upper end of the plunger is connected to a spring, the tension of which resists the downward movement of the plunger. The plunger passes through a gland, the packing of which consists of U leathers; the lower end of the plunger is attached to a stylus which records on a drum rotated, on jerking the instrument, by means of a special mechanism. (In the case of the Kent gauge the recording drum is rotated by a clock.) A shoulder on the lower part of the plunger holds it in position until the pressure is sufficient to move it against the tension of the spring.

The whole assembly is fitted in a case 1¼ in. in diameter. The spring section of the case is commonly partially filled with soap solution, and the well fluids are permitted to enter through ports, the lower portion being isolated by the U leathers. A thermometer pocket is fitted in the lower part of the instrument. A special adapter at the spring end of the gauge allows the instrument to be coupled to a dead-weight tester for calibration.

The gauge of the Standard Oil Company of California, described by Parks and Gibbs in the *Transactions* of the Petroleum Division A.I.M.M.E. for 1934 [6], is of slightly different construction. The spring is situated on the recording side of the packed gland, and the bottom of the piston is protected from the well fluids by means of a pressure transmitting metallic bellows.

A fault with this type of gauge is that the wearing and the renewal of the U leathers is liable to alter its calibration as the friction of the moving plunger may be altered. A skilful operator who has had considerable experience of the instrument is able to renew U leathers without appreciably altering the calibration, but for accurate work it is advisable to calibrate after each run of the instrument; this calibration should preferably be carried out at well temperature to eliminate possible error due to alteration in the tension of the spring.

The sensitivity of these gauges may be greatly improved by adjusting the initial tension on the spring or by using springs of different strength for successive ranges of pressure. Accuracy is usually of the order of 0·5%.

(*c*) Instrument depending on Compression of Volume of Gas.

This type of gauge was designed by A. Laird of the Anglo-Iranian Oil Company and has been extensively used on the Iranian oilfields. It is described by May and Laird in the *Journal* of the I.P.T. for March 1934 [4]. The instrument consists essentially of a closed-end manometer with means for measuring the height to which the fluid level rises in it.

The closed end of the manometer is a glass capillary tube fitted with an upper and lower bulb, the relative sizes of which may be varied to enable the pressure range of the instrument to be varied. The glass tube is fitted inside a container and is securely held in position between a cradle at the bottom end of the container and an adjustable sleeve. In practice it is advisable to insert rubber between glass and metal. A port just above the sleeve allows the apparatus to be filled with mercury and also allows the well pressure to be exerted on the manometer. An outer metal tube, having a long slot to allow readings to be made in the glass tube, is fitted to protect the glass; corks are fitted over the glass to protect it from vibration in the hole. At the top end of the instrument is a thermometer pocket. The outside diameter of the latest design of this gauge is only 1 in.

A record of the level of the mercury at well pressure is obtained by the removal of a silver coating. The silvering is effected by drawing a freshly mixed solution of ammoniacal silver nitrate and a reducing solution of rochelle salts into the capillary. The calibration of the instrument is carried out at the surface after each measurement by fitting the instrument inside a pressure container, maintained at constant temperature, and connected directly to a dead-weight tester. The pressure container is fitted with some means of observing the mercury level in the manometer; for low pressures (0–1,000 lb. per sq. in.) a calibrating chamber may be made from suitably reinforced thick-walled celluloid tubing, but for higher pressures a container with observation windows of thick glass is necessary.

The range of the instrument is adjusted between any two limits of pressure by varying the relative sizes of the top and bottom bulbs; different ranges may also be obtained on the same tube by filling the system with mercury at different degrees of vacuum. The method of carrying out this operation is to remove the slotted tube protecting the glass capillary and to fit a pressure container in its place. The whole system is evacuated through the inlet port and then filled from a reservoir with air dried over P_2O_5. After filling the system with dry air the pressure is again reduced with the vacuum pump to the desired extent, and mercury is admitted until it reaches the bottom of the inlet port. Calculation of the pressure of filling for any range of pressure is simple, provided the deviation of Boyle's Law for dry air and the approximate bottom-hole temperature are known.

Properly operated, this instrument is accurate to within 0·2% and has been used in practice at 2,500 lb. per sq. in. Any length of capillary tube can be arranged to cover a very short pressure range; the gauge is therefore very sensitive. Since the instrument is calibrated at the surface under well conditions there is no scope for serious inaccuracies, but it is essential that clean, dry mercury be always used. The instrument is more robust than might be expected, trouble rarely being experienced due to the glass tube breaking in the hole.

The great disadvantage of this instrument in its present form is that the tube has to be resilvered once it is used at the maximum range. For this purpose it is necessary to open the closed end of the glass tube and seal it again after the silver solution has been passed through it and the silver coating deposited.

The bottom-hole pressure gauges described in the preceding paragraphs are all used extensively in practice. The Amerada and the Humble Oil Company gauges are probably the most popular in the United States. These types of instrument are advised for routine use and for work where a great degree of accuracy is not required, but the manometer type of gauge is definitely to be recommended where greater accuracy than, say, 5 lb. per sq. in. is required. Various types of recording devices are incorporated in the instruments described, but actually the operator would be well advised to discard these for a clock-driven continuous recording device. Specially designed

clocks of sufficiently small diameter are procurable, and conversion should not be difficult except in the case of the mercury spill-over gauge of the Indian Territory and Illuminating Company and the manometer gauge of the Anglo-Iranian Oil Company. In these cases photographic methods might be adopted with advantage. The normal limits of accuracy of the different types of gauges have been discussed, but their successful operation depends to a great extent upon the experience and skill of the operator.

Bottom-hole pressure gauges are usually lowered and withdrawn from the bore hole attached to a piano wire wound on a light spool, which may be either operated manually or driven by a small petrol engine, and the whole equipment is commonly mounted in a car with a box body. The piano wire passes through a packed gland into the well. A suitable outfit, consisting of spool, piano wire, depth-measuring device, and well-head gland, is sold by the Halliburton Oil Well Cementing Company (U.S.A.).

Applied Problems of Bottom-hole Pressure Measurements and Method of Application

The scope of the practical application of bottom-hole pressure measurements to production and development problems depends largely upon the characteristics of the particular underground reservoir under consideration, every unit having particular problems of its own; for instance, certain methods of major importance and value in a fissured and fractured limestone structure, in which fluid migration is very free, may have no application in a close-grained sand reservoir. For this reason it is difficult to make a comprehensive survey of the methods of interpretation and practical application of bottom-hole pressure data; the present article is therefore confined to a discussion of some of the more important uses to which these data have already been put in certain fields. The operator must be left to interpret his own results and to decide upon their practical application to his own particular production problems.

It is necessary to draw a distinction between pressure measurements in static and in flowing wells. The static pressure is a measure of the reservoir pressure at the particular point of observation and provides information of the reservoir as a whole, whereas the pressure in a flowing well provides information relating only to the well in which the measurement is made.

a) Static Bottom-hole Pressures.

The problems to which static bottom-hole (or reservoir) pressures are applied include the determination of the optimum rate of withdrawal for efficient drainage from a unit, the proportion of production which should be drawn from different parts of the same unit for maintenance of hydrostatic equilibrium, and the estimation of movements of edge-water level and gas-oil level. However, before a static pressure is measured for any of these purposes it is of the first importance that conditions at the bottom of the hole should represent true conditions in the reservoir.

Production from a well causes a local reduction of pressure in the formation in the immediate vicinity; the bottom-hole pressure begins to rise, therefore, as soon as the well is closed in and continues rising until equilibrium with the regional pressure in the reservoir is reached. In a fissured limestone structure the return to equilibrium is rapid and in many cases almost instantaneous, but in a close-grained sand reservoir the rise is usually gradual and equilibrium may not be reached for weeks. Successive measurements over a period of time should therefore be carried out until the pressure becomes constant in order to ensure that the maximum has been reached. It is customary to select certain wells, spread more or less uniformly over a unit, for periodical observation of pressure conditions in the reservoir, and in making this selection preference should be given to those wells with the more rapidly rising bottom-hole pressures.

For the purpose of practical application the reservoir pressure at the bottom of each well is correlated to some common level. It is essential, however, in correcting for differences of elevation to use the correct factor for the pressure exerted per foot of oil column under reservoir conditions. This factor is determined by measuring the static pressure at two different depths in the lower part of a well and is the difference in pressure divided by the depth of column.

In many fields the bottom-hole static pressure may be deduced from the surface pressure or, in cases where the reservoir pressure is insufficient to cause the oil column to stand to surface, from the free oil level in the hole. Any free gas above the oil is bled off before the surface measurement is made, and a factor is then applied for the pressure exerted by the oil column. This factor is liable to vary even for wells in the same field, as it depends (among other factors) upon the amount of gas remaining in solution, which in turn depends upon the extent to which pressure is reduced when a well is flowed. Obviously more gas is lost from solution in small producers than in large ones, and the deduced bottom-hole pressure is therefore liable to be in error unless the pressure per foot exerted by the oil column has actually been measured in each well.

The ideal method of producing a reservoir is to maintain a uniform datum pressure (reservoir pressure correlated to a common elevation) over the whole unit, but except in very open type reservoirs this is rarely feasible in practice. It is advisable, however, to fix a limit to the permissible variation, otherwise uneven encroachment of edge water or formation of local gas zones may result. The general rate of decline of pressure in a reservoir is obtained by determining the weighted average pressure of all observation wells. A useful method of comparing pressures in different parts of a reservoir is to construct a pressure contour map from the individual well pressures.

The practical value of a knowledge of reservoir pressures may be best appreciated by an actual case, and in this connexion the well-known East Texas field affords an excellent illustration. For the present purpose it is sufficient to know of the geology of the field that it is a monoclinal structure, 40 miles in length with an average width of about 5 miles, being bound on the east side by a well-defined shore line; the oil sand varies laterally in thickness from zero to 200 ft., and there is also longitudinal variation with the thinnest section towards the south of the field. An important piece of physical evidence is the fact that the crude oil is saturated with gas at only 750 lb. per sq. in. (measured by B. E. Lindsly of the United States Bureau of Mines), although the original pressure at the top of the structure was of the order of 1,600 lb. per sq. in. Static bottom-hole pressures are measured periodically in a large number of wells scattered over the unit. Fig. 2 shows a pressure contour map constructed from pressures measured in these wells in August 1932 (published by Hawthorn in the *Transactions* of the Petroleum Division of the A.I.M.M.E. for 1933 [5]) and Fig. 3 the average weighted reservoir pressure

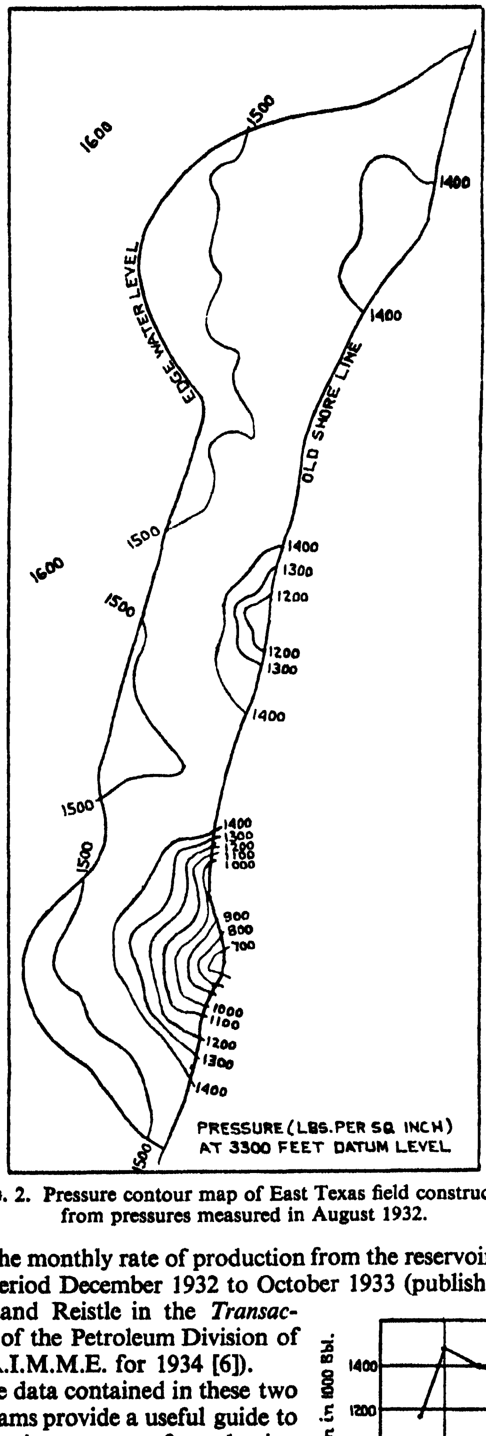

FIG. 2. Pressure contour map of East Texas field constructed from pressures measured in August 1932.

and the monthly rate of production from the reservoir over the period December 1932 to October 1933 (published by Nye and Reistle in the *Transactions* of the Petroleum Division of the A.I.M.M.E. for 1934 [6]).

The data contained in these two diagrams provide a useful guide to the optimum rate of production which should be drawn from the field and to its proper distribution under conditions of efficient unit control. Firstly, the graph of the changes of reservoir pressure suggests that a total production of 800–1,000 thousand barrels per day would soon cause a fall of pressure to below the saturation pressure of the crude, a state which would cause gassing in the formation with resultant falling off in the rate of oil movement in the reservoir; secondly, the pressure contour map shows that the reservoir pressure is only below the saturation pressure in one very small area, proving beyond doubt that no gas dome is forming. The conclusion may therefore be reached that edge water is encroaching as rapidly as oil is withdrawn. It follows that for efficient drainage (i) oil production should be distributed so that a uniform pressure exists along the edge-water line, thus ensuring uniform edge-water encroachment, and (ii) a lower production should be drawn from the areas of low reservoir pressures, where probably the oil sand is thin. The contour map is obviously a good basis for proration purposes.

Reservoir pressure data are put to a somewhat different use in reservoirs of very free fluid communication, such as the sharply folded limestone structures of Iraq and Iran. In these structures the whole fluid system is in equilibrium, and the pressure in any locality, correlated to a common elevation, is uniform from the top of the dome to the water zone; in other words, there is no pressure gradient causing movement across the flank of a structure. Under these conditions it is possible to determine the position of the gas-oil level and of the edge-water level in the reservoir at any time from the measurement of bottom-hole pressures in a gas-well, oil-well, and water-well. The wells may be considered as the limbs of a U tube, the required position of the fluid levels being simply calculated by equating measured pressures. The practical value of close observation of the formation of the gas-dome and of water encroachment in a reservoir is obvious and needs no illustration.

It should be particularly noted that reservoir pressures are not applicable to the determination of gas-oil level and edge-water level in other than reservoirs in perfect hydrostatic equilibrium; for instance, the method is not applicable under conditions such as exist in East Texas where, as may be seen from the contour map, a pressure gradient exists from the water zone towards the top of the structure. In this field the difference of pressure between an oil-well and a water-well immediately below it on the structure is not due merely to the pressure of the fluid column between the two wells, but also to the frictional resistance of the moving fluid—an incalculable factor.

The preceding paragraphs contain an outline of the more general application of a knowledge of reservoir pressures to the proper production control of a unit. In many cases a special interpretation may be placed on the evidence to explain conditions in a reservoir. For instance, the existence of tight zones in limestone structures, or impervious

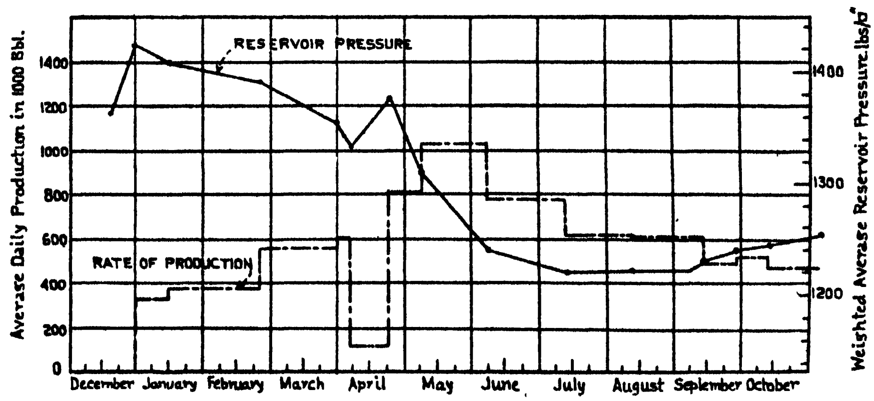

FIG. 3. Graphs showing changes of reservoir pressure with rate of production in the East Texas field for period December 1932 to October 1933.

formations, &c., in sand fields, may often be detected from a study of the variation of reservoir pressure across a unit. In this connexion Wilde (in the *Oil and Gas Journal* of 16 June 1932 [8]) has constructed a number of hypothetical pressure contour maps to illustrate the manner in which pressure data may be interpreted to determine the direction of water drive, the variation of permeability in an oil sand, and the existence of an impervious shale band in a sand horizon. Bottom-hole pressures have also been employed in newly discovered regions to correlate oil and water horizons.

(*b*) Bottom-hole Pressures under Flowing Conditions.

The problems to which flowing bottom-hole pressures are applied include the determination of flow formulae for the purpose of estimating the production decline and flowing lives of wells and for the design of flow strings, the true comparison of the size of producers for proration purposes, and the determination of the productive value of successive intervals of oil-bearing formations.

(i) **The Determination of Flow Formulae.** The flow of mixtures of oil and gas is a very complex study and covers too wide a province to come within the scope of this article. A special article on the subject has been contributed in this treatise by Beale and May, and the reader would do well to consult their work. The subject is briefly referred to here merely to indicate the method of collecting and applying bottom-hole pressure measurements to this branch of production technology.

It is shown that the energy of the expanding gas lifting oil to the surface in a flowing well—calculable, given the physical properties of the mixture—has to do work against gravity, increase in velocity head or kinetic energy, friction, and slippage. Losses of energy due to gravity and kinetic energy are calculable by the normal theory of hydrodynamics. Friction and slippage laws are more complex, and recourse to experiment is necessary in order to determine the constants for their calculation.

May and Laird describe in the *Journal* of the I.P.T. for March 1934 [4] the manner in which these constants were determined by measuring pressure depth relationships in a well flowing at different rates and through different flow strings on a field of the Anglo-Iranian Oil Company. Friction losses were eliminated by flowing the well at a slow rate and through the larger diameter flow strings; a measure of the effect of slippage was thus obtained by determining pressure depth curves and noting their difference from curves calculated on the assumption of no friction or slippage. The friction constants were similarly determined by flowing the well at rapid rates and through the smaller diameter flow strings in order to eliminate slippage.

The measurement of pressures at successive depths in a flowing well presents no difficulty, but it is necessary to ensure that flowing conditions are constant before actual readings are commenced. It is also essential to use a gauge of sufficiently small diameter not to interfere with flow.

(ii) **Comparison of the Size of Producers.** The production of a well is largely influenced by casing size and back-pressure conditions, and it is not therefore possible to obtain a true comparison of the size of producers from surface measurements. The bottom-hole differential pressure production curve of a well provides a true measure of its size and also often throws some light on conditions in the oil-bearing formation in the vicinity. The bottom-hole differential pressure is the difference between the closed-in and the flowing pressure, and is obtained by straightforward measurements; the curve is constructed by determining this value at different production rates.

Fig. 4 shows bottom-hole differential pressure production curves for four producers of the Anglo-Iranian Oil Company. It is obvious from these curves that open flow (maximum production) tests are not necessary to compare the sizes of the wells. The use of similar curves has been suggested as a method of proration in the United States.

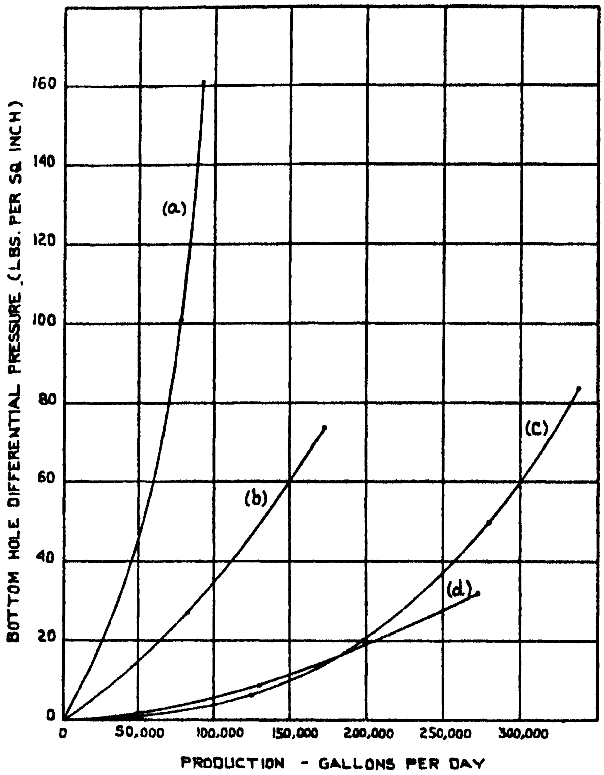

FIG. 4. Bottom-hole differential pressure production curves for four producers of the Anglo-Iranian Oil Company.

Other information of importance may, however, be obtained from these curves. For instance, an increase in the bottom-hole differential pressure of well (*d*) results in a large increase of production, and it would therefore be of considerable advantage to reduce the back pressure by increasing the size of the surface connexions; on the other hand, an increase in the differential pressure of well (*a*) does not improve production appreciably, and no material advantage would be gained by improving its surface connexions.

The bottom-hole differential pressure is also a guide to the permeability of an oil sand or to the size of the fissures in the case of a limestone reservoir. In this connexion the difference in the shapes of the curves (*c*) and (*d*) in Fig. 4 is interesting, as the coincidence at low productions suggests that the two wells have encountered fissures of about similar dimensions. Actually the difference is due to the fact that the reservoir pressure in the case of well (*c*) is but slightly greater than the saturation pressure of the crude; the bottom-hole pressure therefore falls below the saturation pressure at the higher rates of production, and gassing in the fissures begins. In the case of well (*d*) the reservoir pressure is well in excess of the saturation pressure, and the liberation of gas from solution begins some distance up in the casing; the fissures are therefore producing oil, and not a mixture of oil and gas, for all rates of production.

(iii) **Determination of the Productivity of Successive Intervals of Oil-bearing Formations.** The bottom-hole differential pressure may also be employed to determine the productivity of successive sand bodies in a sand reservoir or of successive intervals of formation in a massive limestone formation. The method of obtaining this evidence is to produce the well at different rates from an increasing thickness of exposed oil-bearing formation, at the same time measuring differential pressure production curves. The productivity of successive intervals of formation may then be determined graphically from the series of curves so obtained.

Alternative procedures may be adopted for carrying out the necessary tests, namely, (i) to test as drilling through the oil horizon proceeds, or (ii) to complete drilling and then to test. The first procedure is recommended as the simpler; in this case the well is flowed and the differential pressure production curve obtained for the whole of the exposed formation after each sand body or interval of limestone has been penetrated. The alternative procedure necessitates the use of a flow string and wall packer and it is not therefore advisable to employ it in formation of a caving nature. With this method the packer is first set to allow production from the lowest section of formation and the differential pressure production curve of the section is determined; further sections are then brought on to production by raising the wall packer by stages. It is perhaps unnecessary to point out that accurate results cannot be obtained in formation in which mud flush has been used for drilling purposes.

The graphical method of determining the productivity of each interval of formation from the measured data may be best illustrated by a practical example. Fig. 5 shows a series of bottom-hole differential pressure production curves over 610 ft. of productive formation for a well in one of the Iran fields of the Anglo-Iranian Oil Company. These were determined by the wall-packer method, the packer being set for the first test at 266 ft. from bottom and curve C_1 determined, then at 376 ft. from bottom and curve C_2 determined, until eventually the full 610 ft. of productive limestone was exposed and curve C_4 determined. It is obvious that for any total production P, p_1, p_2, p_3, and p_4 are the proportions coming from the four intervals of limestone, 0–266 ft., 266–376 ft., 376–486 ft., and 486–610 ft.

Information of the productivity of different sand bodies or of successive intervals of formation is of extreme practical value in a reservoir with an enlarging gas-dome or rising edge-water level.

(iv) **Interpretation of the Results of Formation Tests.** A comparatively recent application of bottom-hole pressure measurements is to the interpretation of the results of formation tests. The usual method of testing for productivity is to reduce the size of the hole at the top of the presumed oil-bearing formation, to drill into it with a smaller-sized (rat) hole, and to set a formation tester, such as a Halliburton or a Johnson, on the shoulder of the rat hole.

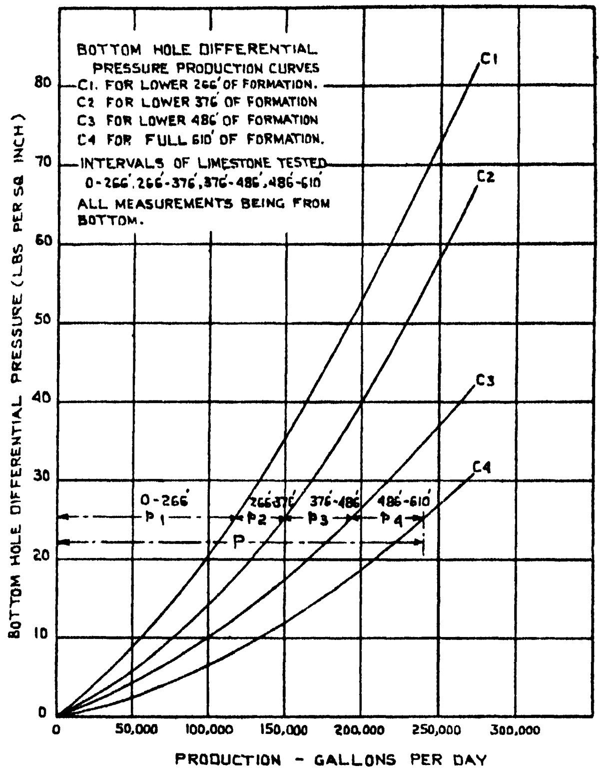

FIG. 5. Example to illustrate graphical method of calculating productivity of successive intervals of formation from bottom-hole differential pressure production curves.

It is now the usual practice to record the pressure at the bottom of the hole during the test by inserting a robust type of recording gauge in a short length of pipe below the tester. The continuous record of pressure indicates (*a*) whether the valves of the tester have opened satisfactorily, (*b*) whether upper formations have been successfully packed-off, and (*c*) the hydrostatic pressure in the formation under test.

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BOTTOM-HOLE TEMPERATURE MEASUREMENT

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Introduction

THE study of the internal heat of the earth began in 1740 with Gesanne's observations on the temperatures of the mines of Alsace. During the nineteenth century detailed measurements from mines, wells, springs, tunnels, and bore holes continued: the advent, however, of modern deep drilling for oil greatly extended our knowledge of the subject in range and precision.

In petroleum technology we are particularly concerned with the distribution of heat in the upper crust of the earth and the relation found to exist between underground temperatures and geological formations, structures, history, and with the general underground conditions affecting oil distribution.

Utility of Geothermal Data

Geothermal measurements often throw light on the presence, shape, type, and age of geological structures such as folds, faults, thrusts, intrusive masses, unconformities, the type of formation, the presence, size, and depth of salt-domes; the depth in a bore hole at which particular strata may be expected, the freedom and direction of the flow of the fluid contents of rocks, such as in normal underground circulation, incoming water to an oil reservoir, and the influence of oil and gas seepages.

Lowering of underground temperature may imply uneconomic production from a field, a stratum, or a well, and is influenced by bottom-hole differential pressure.

The position of a gas-, water-, or an oil-producing stratum in a well may be checked by temperature measurements.

Bottom-hole temperatures, moreover, are essential for accurate measurements of bottom-hole pressures.

Finally, geothermal data may be of considerable use in working out the geological history of a region, often giving a clue to the date of past events, especially where late Tertiary movements have taken place.

Apparatus and Practice

In deep bore holes excellent geothermal data may be obtained with a Haliburton line carrying one or more calibrated maximum thermometers of clinical pattern and deep sea sounding type, giving accurate readings to 0·1° F., and capable of standing pressures of, may be, 5,000 lb., depending on the field and depth.

Electrical resistance methods have been used, also the insertion of alloys fusible at certain temperatures. Self-recording instruments are also on the market.

Readings accurate to 0·1° F. are usually desirable and thermometers should be left in the hole for at least 20 minutes. Jarring and vibration of thermometers are to be avoided. Spring suspensions have been found unsatisfactory. Friction of metal containers against casing generates heat. These effects are avoided by wrapping the thermometer container in a soft material such as burlap. Temperatures are preferably taken at intervals of 200 or 500 ft., depending on the depth of the well.

The bottom-hole temperature is usually the most reliable as, there, disturbing causes have been active for the least time and true rock temperatures are soonest regained after drilling.

Fairly complete depth-temperature curves are needed in the early stages of a field if essential information is not to be overlooked.

Irregularities in the depth-temperature curve should be re-checked. Further, wells in a producing field may, with advantage, be re-measured at suitable intervals to study the change of temperature with production, changing pressures, water-levels, and so on.

Recording Geothermal Data

After recording the depth-temperature curves on well logs showing all relevant information, as to well history and conditions, which may affect the readings, the data may conveniently be presented in the following ways: (*a*) cross-sections showing isothermal lines, geological formations, and topography; (*b*) contour maps showing elevations of isothermal surfaces, with contours on convenient geological horizons; (*c*) isothermal lines on a suitable geological stratum; (*d*) isogradient lines (using average gradients) with suitable geological contours; (*e*) composite graphs showing depth-temperature curves for several wells with common geological horizons marked thereon.

The maximum information is shown by the first and last of these methods, though each of the remainder serves a specific purpose and is useful in certain circumstances.

Elimination of Disturbing and Irrelevant Factors

Considerable irregularities may be noticed on first plotting the results by methods (*a*) or (*e*). These irregularities may be due to (1) disturbing factors, i.e. those due to drilling or field operations or to well conditions whereby the true rock temperature has not been re-established in the hole, or (2) irrelevant data, i.e. those depending on surface relief or other accidental surface features not necessarily dependent on underground geological conditions.

(1) Disturbing factors include the heat generated in drilling, which is greater in hard than soft rocks. In cable-tool holes this quantity may be roughly worked out, using the weight of the tools, the number of blows per minute, the amount of water used, and converting the quantity of energy into heat units generated per foot. Generally this heat is insufficient to affect the temperature of the hole appreciably after more than 24 hours' shut-down owing to the rate of dissipation. In rotary drilling the effect is offset by the circulation of the mud flush, which, being continuous for long periods, alters the temperature conditions throughout the greater part of the hole for corresponding lengths of time afterwards. Bottom-hole temperatures suffer least, as these factors were operative for the least time. The temperatures higher in the hole are diminished or increased, depending on the mean temperature of the flush used compared with the true rock temperature. For these reasons it is best, where accurate results are required, to obtain bottom-hole temperatures at suitable intervals, such as after cementing operations. The main heat gene-

rated by the setting of the cement has not generally been found to be appreciable after a week's shut-down. Theoretically, any momentary heat disturbance of ordinary amount is substantially dissipated after that interval.

Convection may be a considerable source of error, varying considerably with the diameter of the hole, but bottom-hole temperatures, especially when taken in mud, are found to give good results.

Ordinarily, at least 24 hours' shut-down is desirable to obtain a good bottom-hole temperature, but the period varies somewhat with the softness of the formation and the speed of drilling.

Casing has not been found to affect temperatures to a measurable extent.

Gas-, water-, and oil-shows may cause considerable temperature alteration, both at the point of entry into the well and above it, and temperature measurements afford a convenient method for checking the position of such shows owing to cooling by gas expansion on entry into the well.

(2) Topographic relief is reflected in the isogeothermal surfaces to a depth depending on the magnitude of the relief, so that in order to compare well readings, corrections are necessary in order to reduce the topographic effect to a minimum.

Theoretical treatment is difficult and has been given by C. H. Lees [22, 1910].

For normal oilfield conditions a fair approximation may be obtained by choosing a horizontal plane at the average ground elevation of the wells and adding or subtracting the temperature corrections from wells situated below and above this arbitrary elevation.

For a well situated, say, 500 ft. above this plane and in which a gradient of 10° F. per 1,000 ft. was observed we should subtract approximately 5° F. for the influence of the extra overburden and a certain quantity for the lower ground temperature at that height, according to the climate, &c. In this case the high ground would be supposed to extend round the well far enough to influence the bottom-hole temperatures to the full.

If the well, for instance, were situated on the top of one of a parallel series of ridges, small in comparison with the depth of the hole, the temperature effect at depth would be equivalent to that of a plane slightly lower than the average ground elevation.

The fall in mean ground-surface temperature with height may be determined from shallow well readings. It varies from 1° F. to about 5° F. per 1,000 ft. of ascent, according to climate and vegetation, being greater in dry desert regions and at greater heights than in moist country with abundant vegetation. The amount may be checked by referring to the meteorological records of the area as to the fall in air temperature with height.

When deducing approximate ground temperature from air temperatures, from 1·5° F. to 3° F., or even more, must be added according as the climate is wet or dry, and according to the elevation of the locality, the effect being generally less in moist climates and low elevations. See J. Köenigsberger and M. Mühlberg [19, 1910].

The excess of mean ground temperature over mean air temperature varies with the nature of the ground surface, kind of rock exposed, and its moisture content: it depends on the emissivity of the surface and measures the quantity of heat lost by unit surface in unit time with a given difference of temperature.

C. E. Van Ostrand [24, 1934] gives extensive lists of excess ground temperature over air. Their relation, however, to rock types, climate, and surface structure calls for detailed analysis.

It is important to have reliable surface temperatures to derive gradient values and also to serve as a check on well measurements. It should be noted in passing that at 60-ft. depth the yearly variation of ground temperature is negligible.

Special surface features such as marshes and water-logged porous beds such as synclines of sandstones may influence underground temperatures due to the high conductivity and lower surface temperature maintained, especially in countries where there is extensive evaporation during a great part of the year.

When all possible irrelevant surface factors have been accounted for, the residual temperature differences may be considered as due to strictly underground geological conditions and past events.

Geological Causes of Temperature Variation

(*a*) Old Structures.

In old structures, where surface and underground conditions have remained unchanged for sufficiently long, the underground temperatures depend mainly on the conductivity of the rock material, including its fluid contents. Formations of low conductivity will tend to have high gradients and those of high conductivity, low gradients.

The average gradient at which temperature increases with increasing depth in the earth is commonly given as about 17·5° F. per 1,000 ft. descent. It is found, however, that gradients are necessarily very variable, even over small areas.

In the following table are given some approximate heat constants of rock materials, from which will be seen that mineral composition, fluid content, and lamination may give important differences in conductivity and therefore, presumably, in temperature gradient.

Thermal Constants of Rock Materials

Material	*Conductivity*	*Diffusivity*
Anhydrite	0·012	0·023
Rock salt	0·013	0·034
Granite	0·006–0·008	0·0155
Slates:		
(along cleavage)	0·006	0·01
(across „)	0·004	0·005
Sandstones (dry)	0·005	0·012
„ (wet)	0·006	0·01
Limestone	0·005	0·009
New Red Sandstone:		
Dry	0·0025	..
Wet	0·006	..
Quartzose sand	0·001	..
„ wet	0·008	..
Coal	0·001	..
Micaceous Flagstone:		
(along cleavage)	0·0063	0·0116
(across „)	0·0044	0·0087
Ice	0·0021	..
Snow	0·0007	..
Water	0·0014	..

For these and additional determinations, see J. Prestwich [27, 1885]; J. D. Everett [9, 1882, 1892].

It is generally agreed that more accurate data are urgently required as to the thermal constants of rock material, especially in their natural state with their normal water content, but consideration of even the above approximate figures suggests the following:

(*a*) Large geothermal differences of gradients are to be expected where large bodies of salt or anhydrite are present in rocks of average composition.

(*b*) The virtual conductivity of water-saturated rock masses increases rapidly with increasing permeability and water content, thereby suggesting that free fluid conditions may have a large effect on heat distribution.

(*c*) Appreciable temperature differences may arise due to the dip of certain fissile rocks.

As regards granite, the published conductivity figures differ widely, the average being about 0·0055, which alone would give no grounds for considering that the depth of the granite basement could affect isogeotherms. It is significant, however, that all figures for the geothermal gradient in granite, as given in J. Prestwich [27, 1885], are high, giving an average gradient of 24·1° F. per 1,000 ft. as against the 20° F. to 22·2° F. per 1,000 ft. which he finally decided upon as an average figure for crustal rocks. Weight is added to the granite figures by their uniformity compared with the divergent laboratory determinations.

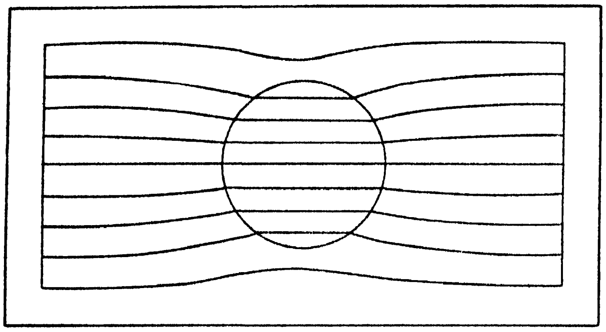

FIG. 1. Lines of force due to sphere of low conductivity in a medium of high conductivity. Compare Figs. 5 and 6.

For the influence of rock masses of various types on earth temperatures, consider first of all an equivalent electrical example. Fig. 1 (after a figure due to Kelvin) shows the lines of force for a sphere of poorly conducting material placed in a better conducting medium. The field of force due to a good conductor placed in a poorly conducting medium is shown in Fig. 2, which may be taken as typifying the conditions set up by an old salt plug.

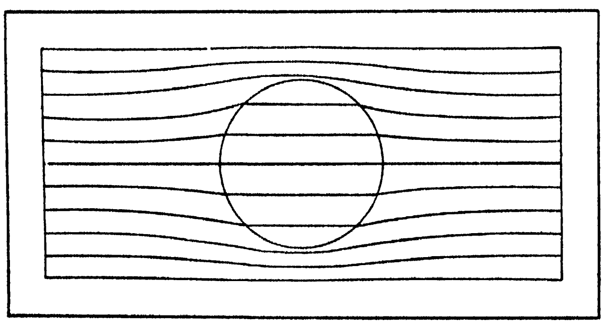

FIG. 2. Lines of force due to sphere of high conductivity in a medium of low conductivity. (Ref. Normal Salt Plug Conditions.)

It will be apparent that the resulting geothermal field will depend on the size and shape of the plug and on its proximity to the surface. If the plug be buried deeply, as exemplified in Fig. 1, then we expect to find a high gradient in the rocks above it, increasing to a maximum in the immediate neighbourhood of the top of the plug. Down the flanks a decreasing gradient would be expected, and at a certain depth the isogeotherms of the country rock would be depressed against the plug, there being low gradients within the salt mass itself.

The closer a salt plug approaches to the surface the less the high-temperature abnormality above it. Down the flanks the isogeotherms of the country rock tend to rise on approaching the plug, this effect being observed down to a certain depth (depending on the size and shape of the plug) below which the whole effect is inverted and, finally, below the salt mass, the country rock is cooler than at equivalent depths elsewhere.

For an exposed salt plug, not elevated, the horizontal equitemperature plane is at the surface of the ground, so that all isogeotherms below this will be depressed on approaching the salt plug.

It will be seen from these considerations how isolated temperature data may be quite insufficient to provide information as to the whereabouts, size, or depth of the plug, but that fairly complete depth-temperature curves for wells in the vicinity may be necessary for useful deductions to be possible.

By the aid of Figs. 1 and 2 the thermal effects due to most types of structures met in nature, where high conducting strata such as salt masses or thick anhydrite sequences are brought into juxtaposition with average shales or marls, may be readily deduced.

As an example, consider a group of anhydrite and saliferous beds thinning out between an upper marl and a lower limestone series as shown in Fig. 3, in which it will be noted that high gradients are present where the isogeotherms are elevated above the salts and anhydrites, low gradients persist within them, and the isogeotherms are depressed on approaching them.

Several examples have been given diagrammatically by M. W. Strong [28, 1929]. See also W. B. Lang [21, 1930].

Inequalities of conductivity in rocks are also brought about by rock deformation where re-orientation of the mineral particles has taken place. It has been found that the conductivity along the bedding planes may be higher than the transverse conductivity in the ratio of 6:4 which might give an appreciable effect if sufficient strata were involved.

Underground circulation of the fluid contents of formations may be an important factor affecting temperature conditions as, from the above figures, it is seen that wet permeable rocks show higher conductivities than dry. In oil reservoirs where conditions favour convection, as on the long plunging ends of anticlines of permeable limestones, very high temperatures have been recorded at both the Masjid-i-Sulaiman and Haft Kel fields in SW. Iran on the north-west pitching ends, while lower temperatures are present towards the south-east ends nearer to the outcrop.

This effect can apparently be increased by the presence of high ground over the pitching end, thereby accentuating the gravity difference of the water or oil at equivalent depths. Incidentally, such an effect may entail non-horizontal water- and oil-levels if low permeability is present between the warm and cool regions. It will be noted that free fluid conditions are necessary for the maximum temperature effect due to such convection conditions, which may persist for long periods, with rising currents under warm regions and descending currents elsewhere.

(*b*) Strata not in Geothermal Equilibrium.

In considering the alteration of temperature conditions of the rocks underground it is necessary to consider the

relative diffusivities of the strata, of which certain values generally accepted at present are given in the table above.

Thermal changes take place slower in rocks of low than in those of high diffusivity, but in all rock materials any disturbance of thermal conditions takes place extremely slowly, so that geological changes may leave traces in thermal anomalies observable for several million years afterwards. Fig. 4 illustrates the residual effects at depth due to gradual changes of surface temperature extending over various intervals of time. It will be seen that the effect of late Tertiary changes should, if originally large enough, be still observable under favourable conditions.

Alterations of surface temperature may be brought about by climatic changes, elevation of the country, emergence of strata from beneath the sea, and virtual alterations brought about by rapid denudation or by structural uplift combined with rapid peneplanation.

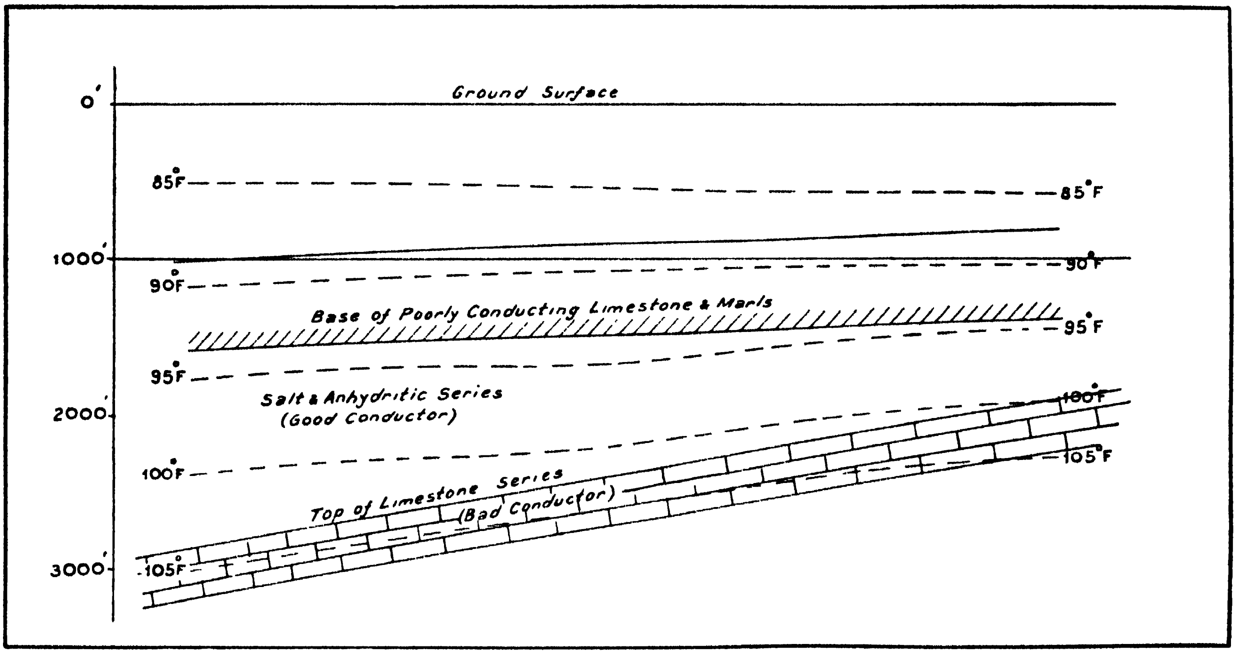

FIG. 3. Isogeotherms where good conductor thins out between poor conductors (Masjid-i-Sulaiman, Iran.).

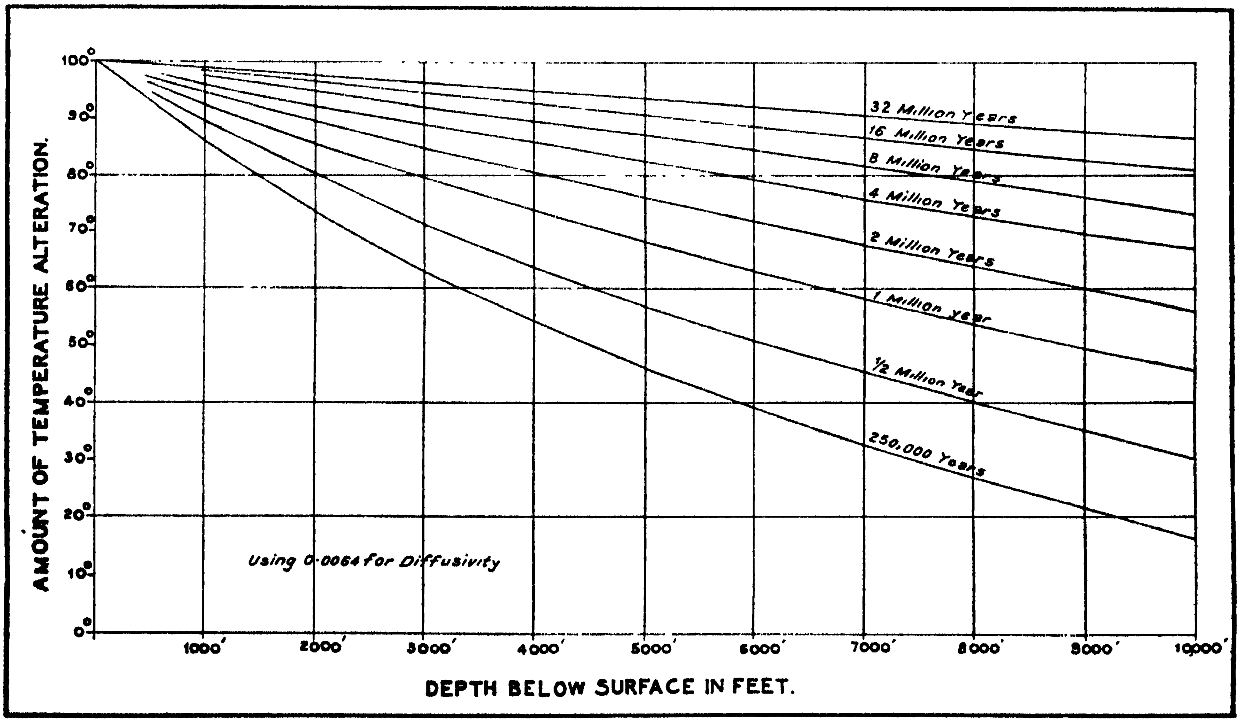

FIG. 4. Residual geothermal effects due to steady surface temperature changes over various periods of time.

In SW. Iran, for instance, where some 10,000 ft. of late Miocene and Pliocene strata have, in places, been denuded after rapid uplift, the effect is roughly equivalent to a gradual surface temperature alteration of about 100° F., in that rocks, whose temperature at 10,000 ft. would have been about 180° F., have been exposed to the surface and reduced there to about 80° F. A geological section across

the Haft Kel structure in Iran (Fig. 5) illustrates this point. It will be seen that the isogeotherms are still arched across the structure.

In this case, throughout a large part of the field, the isogeotherms are sufficiently regular to enable a forecast depth to be given to the producing limestone, accurate to within narrow limits.

Surface thermal conditions may change in other ways: alteration of physiography, with or without geological movement, may take place, with consequent realinement of drainage systems, redistribution of lakes, alteration of vegetation, modification of the flow of underground waters, and removal of ice sheets. For the effect of past climates and events reference may be made to A. Geike [10, 1903], A. C. Lane [20, 1923], and M. W. Strong [28, 1933].

The history of each district must be examined for the most likely factors to have influenced its thermal conditions. Geological events which lower the surface temperature tend to increase the temperature gradient and vice versa.

Geothermal conditions are also closely dependent in geological structural changes such as faults and thrusts. A thrust, for instance, in which cool surface rocks are buried to a depth of 5,000 ft. or so will necessarily entail a lowering of the local temperature gradient until the overthrust mass has heated up to the temperature appropriate to its new depth. A fault of large throw will entail an irregularity in the isogeotherms crossing it, until such time as equilibrium is established. The larger the throw the longer will the effect be noticeable. If the fault bring rocks of high against those of lower conductivity, a change of gradient will be maintained with a consequent rise of isogeotherms passing into the bad conductor.

Fault systems, however, are frequently permeable to waters, so that high or low temperature near a fault cannot be readily attributed to any one cause. Active fault systems are liable to show high temperatures due to friction. Gas-escape up faults causes cooling, not only in the fault itself but in the reservoir being tapped.

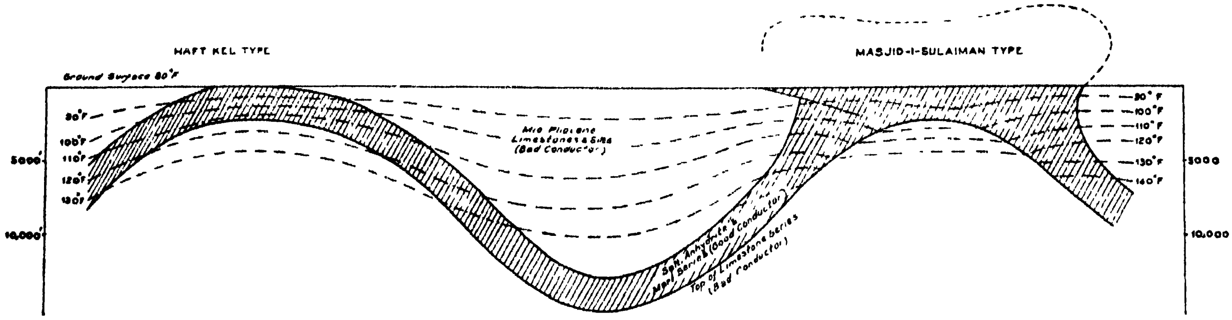

FIG. 5. Combined sketch section across parts of Masjid-i-Sulaiman and Haft Kel fields, SW. Iran. (By courtesy Inst. Petr. Tech. from *World Petr. Cong.* 1, 128 (1933).)

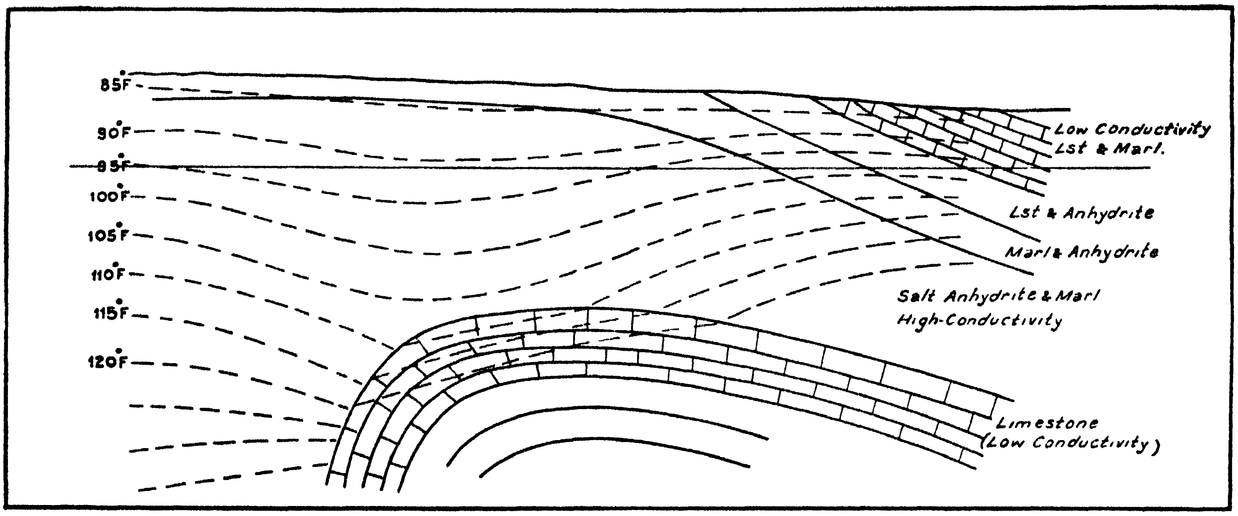

FIG. 6. Isogeothermal section, SW. Iran. Poor conductor beneath good conductor. With partial surface blanket.

A salt plug is liable to cause high temperatures when active or young as the salt may come up from great depths, its rate of subsequent cooling depending on its dimensions. An opposite effect is caused where a large mass of salt or other incompetent rock mass is piled up on the flank of a structure, as considerable time is necessary to re-establish the normal gradient through it. Structures may be reflected in the isogeotherms where a body of salt or other incompetent material has been squeezed out from between other formations, resulting in a high-temperature lower formation being brought close up beneath a considerably cooler formation. Such a condition may be contributory in establishing the thermal field shown in Fig. 3.

Oil- and gas-escape from reservoirs is a cooling process, and if it has gone on for a long time may lead to appreciably lower temperatures. Such a condition appears to be present in a fold near Haft Kel field, SW. Iran, where the L. Miocene limestone is 9° F. cooler than at the corresponding depth on the adjacent oilfield. Masjid-i-Sulaiman field, SW. Iran, where very old seepages are active, is several degrees cooler than Haft Kel at all depths within the

oil zone, though the extensive cover of high-conductivity strata would also contribute to this effect. The conditions are shown in Fig. 5, which is a sketch-section across both fields. Compare also Fig. 6.

In producing oilfields the wells may show a gradually decreasing bottom-hole temperature with time, due to gas expansion on production. This effect has been found in all wells in Iran on which repeated observations have been made after a sufficient lapse of time.

A further temperature effect in producing or seeping fields is the rise or fall of temperature due to incoming waters. In Iran, fields with old seepages show low temperatures towards the nearest possible source of incoming waters, and high temperatures in the direction from which oil is or has been feeding up into the structure. In fields which have been static until produced, the first effect of water rise is temperature elevation, as in Mexico (E. De Golyer [11, 1918]).

There remains to mention the low gradients frequently present in thick accumulations of sediments in young (late Tertiary) synclines. See Fig. 5.

The local thermal effects due to such processes as pyritization, oxidization, hydration (as of anhydrite), gypsitization of limestones and marls, decomposition of igneous rocks, radioactive heat generation, and the heating effects of volcanic intrusive rocks do not here call for detailed discussion.

The possible heat effects due to oil-bearing strata have not yet been studied in sufficient detail to warrant definite conclusions.

Temperature Gradients

In this article the term 'geothermal gradients' is used to mean the rise of temperature per unit increase in depth. It is frequently quoted as the increase in depth per unit increase in temperature. The term 'reciprocal gradient' is now generally used in the latter sense. An average earth gradient is difficult to arrive at as most gradients are measured either in mines where special conditions are present, or in bore holes on anticlinal structures. J. Prestwich [27, 1885] arrived at a figure of about 21° F. of per 1,000 ft., but on the Masjid-i-Sulaiman structure in SW. Iran, gradients of from 5° F. to 13° F. per 1,000 ft. have been observed and from 9° F to 19° F. per 1,000 ft. on the Haft Kel field.

It will be seen from a consideration of the factors above discussed and from the figures given in this article that gradients may vary considerably both with depth and locality. The isothermal dip should also be borne in mind. When quoted, therefore, full geological data (including physical and chemical conditions) are necessary for any assessment of their significance. Used apart from the full depth-temperature curves and other relevant data their value is considerably restricted.

To take a simple example such as a buried salt mass in a homogeneous marl series, the gradients observed depend upon its size, depth from surface, and the position of the mass relative to the well and point of observation.

When geological conditions are fully considered, gradients assume considerable significance as has been shown by A. C. Lane [20, 1923] with reference to past climates. The methods there used are applicable to other types of changing conditions.

Summary of Results

In the United States coincident geothermal and geological anticlinal conditions were found in Wyoming, at Salt Creek, Natrona Co., by W. T. Thom [30, 1925]; in California, at Long Beach field by A. J. Carlson [5, 1930]; in Oklahoma, on the Cromwell and Garber fields, and in Kansas on the Eldorado field, by J. A. McCutchin [23, 1930]; in Texas, on the Big Lake field and on the following salt-domes: Grand Saline, Van Zandt Co., Humble, Harris Co., Blue Ridge and Long Point domes in Fort Bend Co., by E. M. Hawtoff [13, 1930].

C. E. Van Orstrand [24, 1934] indicates that similar conditions are to be found on many other anticlinal structures and gives comprehensive lists of geothermal data now available, including the results of his own long series of researches. J. A. McCutchin's [23, 1930] geoanticlinal conditions with geothermal reflection from Wewoka to Oklahoma city are of special interest. In Mexico, E. De Golyer [11, 1918] described the geothermal conditions and drew attention to the high temperatures in oil- or water-bearing strata in regions of recent volcanic activity.

At Boryslaw field, Galicia, H. Arctowski [2, 1925] showed well-defined coincident geothermal and geological anticlines.

In the Pechelbronn oil-bearing region, Lower Alsace, I. A. Haas and C. R. Hoff [12, 1929] have described the geothermal conditions. The cross-sections given in their paper may be interpreted as follows: After the main folding and denudation took place, the commonly found thermal conditions approximately obtained, with the isogeotherms dipping south-east with the strata, but less steeply as time went on. Subsequently considerable normal strike faulting took place, with sufficient down-throw towards the north-west to cause the isogeotherms to dip to the north-west in the opposite direction to the dip.

In Iran, on the Anglo-Iranian Oil Company's Masjid-i-Sulaiman and Haft Kel structures, we have geothermal reflections of geological anticlines though the conditions are complicated, in the crestal region of the former field, by a subsidiary geothermal syncline due, apparently, in part, to the cooling effect of seepages of long duration and to the long-exposed overburden of strata of high conductivity. Compare also with Figs. 1 and 6. In the area shown in Fig. 6 tectonic piling up of strata may contribute to the effect; seepages are absent.

In these fields the very complete geothermal data collected over some 10 years under the direction of D. Comins and L. A. Pym have thrown light on many of the geothermal problems discussed above and some general conclusions from a study of their data have been published by M. W. Strong [28, 1930; 29, 1933].

More recently, Schlumberger has further developed the instrumental side and has specialized on the use of geothermal evidence for the location of underground water, gas and oil sands, as well as its application to cementing problems.

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BOTTOM-HOLE SAMPLES

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THE main purpose of this article is to review the principles involved and the methods employed in the collection of samples of reservoir crude under full reservoir pressure. The date which may be obtained by examination of the samples and the scope for application of such data in the scientific development and control of oilfield reservoirs are briefly indicated. For completeness, a short discussion is also included of bottom-hole sampling not carried out under pressure.

The literature on the subject of bottom-hole pressure samples is scanty and has its beginnings in a paper by Sclater and Stephenson [18] in October 1928 describing some preliminary investigations carried out in Oklahoma by the Marland Production Company. No further report was published.

The only exhaustive investigations regarding which there is any published record are those initiated by the Anglo-Iranian Oil Company in the Masjid-i-Sulaiman limestone field, Iran, in 1930 and those initiated by the U.S. Bureau of Mines in the East Texas sand field in 1932. The former have been reported in papers by Pym [16], Jones [5], and Comins [3], to the World Petroleum Congress in 1933, and also, with more specific reference to the closely allied investigations into bottom-hole pressure measurement and efficiency of flow in wells, by May [13, 14] and Laird [14] in 1934. It may be mentioned that similar investigations on other higher pressure limestone fields in Iran recently carried out and in progress have confirmed the soundness of the general principles established for limestone fields by the investigations at Masjid-i-Sulaiman and have shown that these are not merely of local application to one particular reservoir.

The U.S. Bureau of Mines investigations in East Texas were reported by Lindsly in 1933 [10]. These were on similar lines to those carried out in Iran, except that the question of variation in the characteristics of bottom-hole samples collected at different points in the reservoir was not studied. Further work by the U.S. Bureau of Mines in the Oklahoma City and Crescent (Okla) fields has been reported by Lindsly in 1934 [11] and 1935 [12].

As far as the author is aware the only other fields from which any results of examination of bottom-hole pressure samples have been published are Hobbs [20, 1933] (New Mexico), Keokuk Falls [4, 1935] (Oklahoma), and Sugarland (Gulf Coast) [17, 1935]. Interest in this subject has, however, received considerable impetus from the realization of the practical importance of results to date, emphasized in recent reviews of their commercial application in oilfield practice such as that of Morris [15] before the American Institution of Mining and Metallurgical Engineers in October 1934. The U.S. Bureau of Mines are continuing an active research programme [2, 1934] and the American Petroleum Institute are extending the valuable Research Project no. 37 (on the occurrence and recovery of Petroleum, under the direction of Lacey) to include a study of bottom-hole pressure samples [7, 1934]. It is mentioned that these are being collected by various operating companies working in collaboration with the A.P.I., so that there is little doubt that a number of sample-taking instruments have recently been evolved in the U.S.A., of which the details of design and results obtained have not yet been published.

It will be appreciated from the general review of progress to date given above, firstly that bottom-hole pressure sampling is a recent development in petroleum technology, and, secondly, that a very considerable increase in our knowledge of its scope for application in different types of reservoirs may be expected in the course of the next year or two. The discussion contained in the present article of methods in current use is, therefore, necessarily incomplete and the discussion of interpretation of data possibly premature in certain respects, in that some points are still subject to confirmation in reservoirs of different type from those in which exhaustive investigations have so far been made.

Bottom-hole Samples not collected under Pressure

Bottom-hole sampling in which no attempt is made to collect the sample under pressure has, of course, been normal oilfield practice since the industry began, and a brief note of its usual applications is sufficient. These are:

1. For determination of oil-water level by bracketing of samples.

This is useful in a deep well of small diameter where the pick up of a float (sinking in oil and floating in water) cannot be felt. When sampling under these conditions it is better not to rely upon valves, but merely to run an open dipper and leave it in position for a short time to allow water to displace oil, if the dipper is below oil-water level. A convenient design which saves time in bracketing, by reducing the number of runs necessary, is to use a length of 6 to 10 ft. of say 2 in. clarified celluloid tubing, plugged at 1-ft. intervals and perforated immediately below each plug for ingress of oil or water to each compartment.

A point that is often overlooked when sampling for oil-water level in wells which have an oil-pressure at the flow-head, is that in a small producer the oil-water contact in the hole may be appreciably higher than oil-water level in the reservoir if there is any flow of oil whilst running the sample taker. For this reason leakage past the running in gland should be reduced to a minimum. It can be entirely prevented if the sample taker is run on piano wire.

2. For determination of gas-oil level by similar methods, in cases where a gas-well has been deepened to oil in the same reservoir.

A point to watch is that, after withdrawal of the dipper into the container at the flowhead, the gas-pressure of the latter should be vented down slowly, otherwise the whole of any oil may be ejected from the dipper by rapid evolution of gas from solution. Precautions are also necessary to ensure that oil does not drip down the line into the dipper. For these reasons, if a float cannot be used, it is usually more satisfactory to measure gas-oil level by observing the depth of oil wetting of a steel tape; or, if the casing is oily, to lower a long clarified celluloid tube to successive depths and observe directly the level of internal wetting.

3. For determination of the point of ingress of an upper

water-show to an oil- or gas-well, or of an upper oil-show to a gas-well.

An open container with an inverted skirt of packing, leather or rubber, so that any liquid trickling down the side of the casing or hole will be trapped, may be run to successive depths.

Technique of Collecting Bottom-hole Samples under Pressure

In the technique of successful bottom-hole pressure sampling careful attention to the following points is essential:

1. Before taking a sample the well must be conditioned so that the crude around the foot of the well is truly representative of the reservoir crude under static conditions. This is done by flowing the well at a very low rate of production for a sufficient period before collecting the sample to empty the casing at least once—preferably several times. The permissible rate of flow is dependent upon the size of the well, the essential point being that it shall not be sufficient to cause any measurable bottom-hole pressure drop during flow. The well may be closed in at the time of taking the sample, but this is not necessary if the bottom-hole pressure drop during flow has been very small.

The reason for so conditioning the well is that if it has been on production prior to the test at a production rate causing any appreciable bottom-hole pressure drop, the crude in the well and in the reservoir rock in its immediate vicinity may have evolved some of its gas from solution, and the sample obtained would not be representative of the normal reservoir crude in the area. (This would in fact only occur if the bottom-hole pressure had been reduced below the 'saturation pressure' of the reservoir crude, but before taking the sample the saturation pressure—which will be defined later—is unknown.) If the well has been standing closed in for a long period the crude in the well also becomes to some extent degassed by processes of convection and diffusion in the well.

It is unnecessary to condition the hole prior to sampling if the well to be tested is a large one and has been on production at any time within the three months preceding the test at a rate known to cause no appreciable bottom-hole pressure drop during flow.

2. The temperature at the depth of collection must be measured. It is not essential that this should be done at the same time as the sample is collected, but the information is necessary before the sample is tested after withdrawal to surface.

3. The approximate pressure at the depth of collection must be known before the sample is taken. Accuracy not being essential, this can in most cases be calculated. Otherwise a bottom-hole pressure indicator must be run before running the sample taker.

4. It is never advisable to be satisfied with the results obtained from one sample at a given depth. Either two sample takers should be run in series on the same line, or a check run should be made. If on withdrawal to surface the tests outlined later show that both samples are saturated with gas to the same pressure (within the limits of experimental error) at reservoir temperature, the samples may be accepted as satisfactory and there is no need to duplicate the further tests on the samples. It is not essential that the actual pressures (as distinct from the gas saturation pressures should agree, as it is the characteristics of the reservoir crude at gas saturation pressure which require to be determined and the actual pressure of the reservoir crude can be determined with far greater accuracy by means of a bottom-hole pressure indicator.

5. The sample taker used should fulfil the following requirements:

(*a*) There must be no possibility of contamination of the sample by crude entering it from higher levels in the well whilst lowering the sample taker. If the design of sample taker is such that higher crude can enter it whilst lowering, it must also permit of adequate purging of such crude from the sample taker before the final sample is collected.

(*b*) The sample collected must consist of crude with the whole of the gas which is dissolved in it under reservoir conditions. Whilst admitting the sample the pressure on the remaining crude surrounding the sample taker must not be reduced, otherwise gas may be evolved from it and also enter the sample taker. If, therefore, the design of sample taker is such that the sample enters it suddenly, the capacity of the sample taker must be small in relation to the size of hole.

(*c*) Preferably the rate of entry to the sample taker should be such that there is no appreciable pressure reduction, even momentarily, on the sample actually admitted. If there is, gas will be immediately liberated from solution and the saturation pressure of the crude sample lowered. If, on account of other considerations, the design of sample taker is such that this does occur, facilities must be provided for redissolving the gas at surface in the crude from which it was liberated before determining the saturation pressure. This may be done by pumping in mercury or water through a suitable connexion, until the actual pressure of the sample is well above any possible saturation pressure, and agitating.

(*d*) There should be no possibility of the sample being collected at the wrong depth. Although if this does occur it will be detected by the check run, unnecessary work and delay is entailed. For this reason the use of 'messengers' (small annular weights dropped down the line) is to be deprecated as a means of actuating the mechanism by which the valves are opened or closed, except in holes which are known to be straight. It has been found that in crooked holes messengers cannot be relied upon. The reason would appear to be that they are liable to hang up whilst running in on account of the line hugging the walls of the hole. On falling later whilst pulling out, a false sample is obtained too high in the hole. For use in crooked holes a selection may be made from one of the more positive means of admitting the sample which are mentioned later.

(*e*) Obviously the sample taker should not leak during or after withdrawal to surface. For this reason small valves are preferable, and non-return valves should be plugged off on arrival at surface. A point to be appreciated, however, is that in the case of a sample collected at a pressure substantially above saturation pressure, a small leak of oil will not vitiate the usefulness of the data to be determined from the sample unless the leak is sufficient to reduce the actual pressure of the sample down to the pressure where gas begins to be evolved from solution. In the case of samples at saturation pressure, or below saturation pressure with evolved gas above the oil, a small oil leak will be far less deleterious than a gas leak. For these reasons inlet valves should preferably not be located at the top of the sample taker. Also, of course, gas is more likely to leak than oil.

(*f*) It is a considerable advantage if the sample taker is made light enough for two, in series, to be run on piano wire through a Halliburton gland. A great saving in time is thus achieved in rigging up and in check readings.

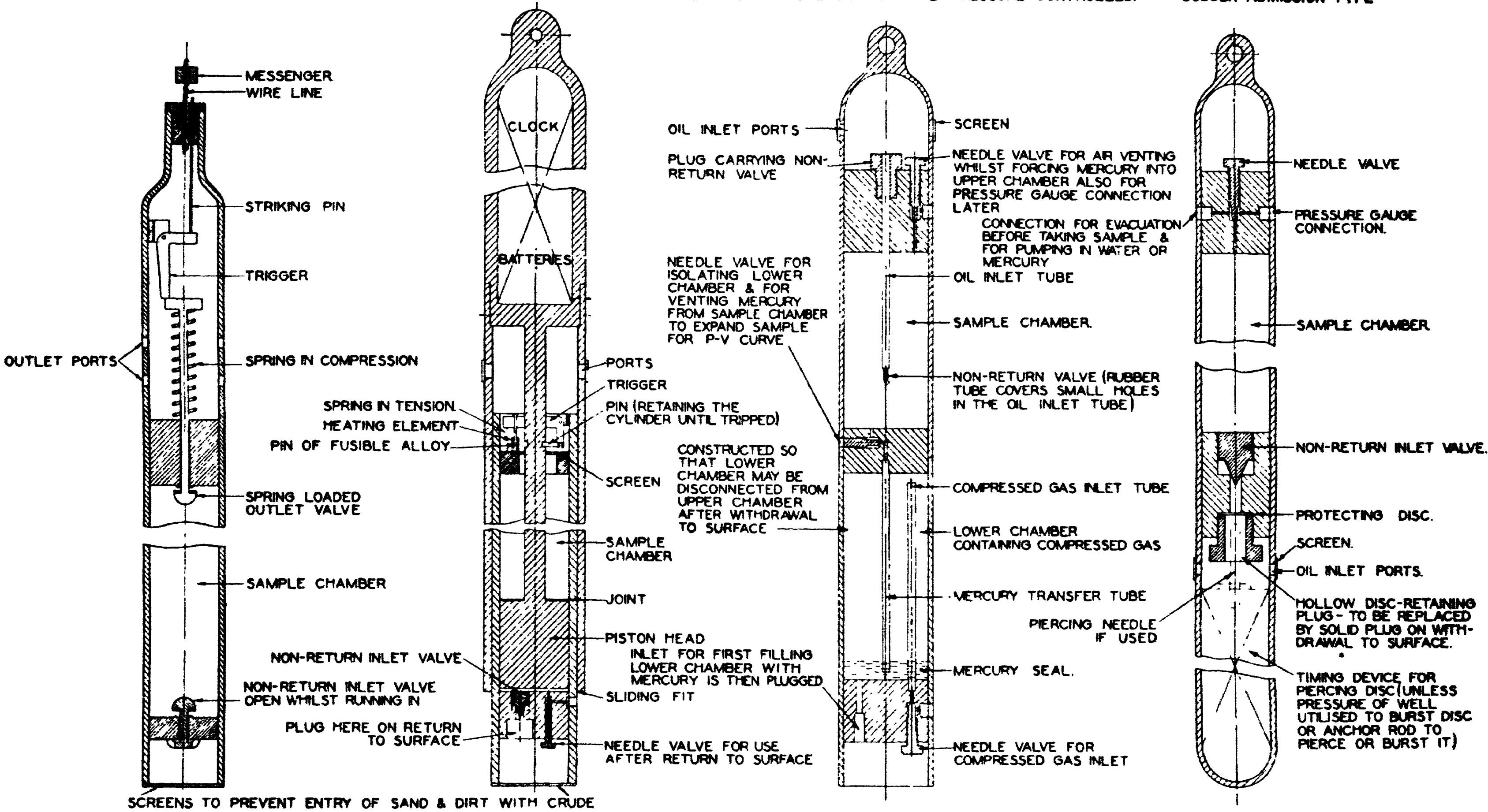
TYPES OF BOTTOM-HOLE PRESSURE SAMPLE TAKERS.

FIG. 1. FLOW-THROUGH TYPE.

FIG. 2A. SLOW-DISPLACEMENT TYPE - PISTON CONTROLLED

FIG 2B. SLOW-DISPLACEMENT TYPE - PRESSURE CONTROLLED.

FIG. 3. SUDDEN ADMISSION TYPE



NOTE BEING INTENDED TO ILLUSTRATE WORKING PRINCIPLES CONSTRUCTIONAL DETAIL IS OMITTED AS FAR AS POSSIBLE FROM THE DIAGRAMMATIC SKETCHES ABOVE REFERENCES GIVEN SHOULD BE CONSULTED FOR DETAIL

Furthermore, as all flow past the line can thus be prevented, sample taking is practicable in very high pressure wells.

(*g*) Much time is saved if the design of sample taker is such that the maximum amount of data can be determined direct without the necessity of transferring the sample under pressure to other apparatus.

(*h*) For use after withdrawal of the sample to the surface a positive valve must be incorporated in the sample taker controlling connexions for a pressure gauge and for outlet piping from the sample chamber. These are essential both for observing data such as can be determined from the sample whilst still in the sample taker, and also for transferring the sample under pressure to other apparatus.

6. On arrival at surface the sample taker should be placed in a water-bath, thermostatically controlled at the temperature at which the sample was collected. Provision should be made to allow agitation of the sample taker and of the water-bath in order to allow the sample to reach equilibrium. When this is reached, as indicated by the pressure gauge steadying, the sample is ready for examination.

The different types of sample taker in use will be discussed later. In order that their relative advantages and disadvantages may be appreciated, it is desirable first to outline the data which may be obtained from examination of the samples collected. It is not within the scope of this article to discuss the detail of methods of determination.

Outline of Data which may be obtained from Bottom-hole Pressure Samples

1. **The Saturation Pressure**—which is the critical pressure at which gas first begins to come out of solution as the pressure on it is reduced. The pressure should be reduced by bleeding off an independent liquid, e.g. water or mercury, in contact with the oil under the pressure of the sample.

2. **The Total Dissolved Gas Content**—which is the total volume of gas (measured at N.T.P.) in solution at the saturation pressure; and the **Solubility Curve**, which is the curve relating the volume of gas remaining in solution as the pressure of the sample is reduced by stages to atmospheric pressure, with the pressures at such stages.

These are obtained by bleeding off and measuring the volume of gas evolved from solution at each pressure stage, the sample, still maintained at reservoir temperature, being agitated at each stage until no further gas is evolved.

3. **Shrinkage**—which is the percentage decrease in volume of the sample caused by the evolution of gas from solution, and is directly measurable.

4. **Pressure/Volume Curve**—which is the curve relating pressure with the volume of crude and gas occupied at any given pressure by unit volume of crude at saturation pressure.

This is obtained by direct expansion of the sample. It is essential that an independent liquid, e.g. mercury, be withdrawn to reduce the pressure and allow space for expansion. See May [13, 14, 1934] for detail.

5. **The Physical Properties of the Reservoir Crude and of Crude at varying Saturation Pressures.** *Compressibility and Thermal Expansion* of the reservoir crude may be determined by raising the pressure of the sample above saturation pressure and varying the pressure or temperature.

The Specific Gravity, Surface Tension, and Viscosity of the reservoir crude should be determined, and also curves showing the increase in each of these as gas is evolved from solution. For methods of determination involving transfer of the sample see Jones [5, 1933], Lacey [8, 1932; 9, 1934], and Swartz [19, 1931]. The specific gravity of the reservoir sample may also be computed from direct weighing of the full sample taker if it is of light enough construction relative to the volume of the sample. For viscosity determinations a jet type of H.P. Viscometer has also been used, with high-pressure quartz windows.

Any of the above-mentioned data, except as regards surface tension and viscosity, can be determined without transferring the sample to other apparatus, provided the sample taker is of suitable construction. However, a sample taker suitable for the direct determination of a pressure/volume curve is unsuitable for other purposes. This is because the capacity of the container in which the sample is expanded must be very large in proportion to the volume of the sample at reservoir pressure, in order to permit expansion to low pressures.

Types of Bottom-hole Sample takers in Use

In broad definition the design of all bottom-hole pressure sample takers is based upon one or other of the three following working principles:

1. The chamber in which the sample is to be collected remains open until an upper and a lower valve are closed at the required depth, the fluid in the well flowing through the chamber on the way down.

2. The sample chamber remains closed until the inlet valve is opened at the required depth, when the sample is slowly admitted to the chamber by means which ensure that there shall be no reduction of pressure, even momentarily, on the fluid being admitted.

This is achieved by either of two methods:

(*a*) Slow displacement of a piston in the sample chamber as the reservoir fluid enters.

(*b*) Slow displacement of mercury from the sample chamber as the reservoir fluid enters, the displaced mercury entering another chamber against a back pressure exerted by compressed gas with which the second chamber is filled before lowering the sample taker.

3. The sample chamber remains closed until the inlet valve is opened at the required depth, when the sample is suddenly admitted to the chamber, no precautions being taken to prevent momentary reduction of pressure on the reservoir fluid.

Type sketches illustrating in turn sample takers based on these principles are attached, mechanical detail being omitted. In considering the advantages and disadvantages of each type stated below it must be remembered that it is impossible in any one design to fulfil all the requirements stated earlier. In practice much must be sacrificed to lightness and simplicity.

1. The Flow Through Type, Fig. 1.

The upper valve is retained open when running in by a spring which is tripped in the type illustrated by a trigger actuated by a messenger dropped from surface. The lower valve may be a non-return valve which remains open whilst running in, and seats itself by its own weight when the sample taker comes to rest, or may be controlled by the same spring as the upper valves. Knife-edge valves are used with soft replaceable seats of hard rubber, phosphor bronze, or aluminium.

Sample takers of this type are described in detail by

Lindsley [10, 1933] and by Sclater and Stephenson [18, 1928–9].

Advantages:

(*a*) No pressure reduction on sample whilst being admitted.

(*b*) Light enough to run on piano wire.

Disadvantages:

(*a*) Careful precautions necessary to ensure that sample is not contaminated by crude at higher levels. These involve flowing the well at a low rate after lowering the sample taker and also raising and lowering it a number of times near the desired depth.

(*b*) Difficulty of avoiding leakage with the large valves essential for adequate flow through the sample taker for purging purposes.

(*c*) Lack of positiveness of 'messenger' trips. (N.B. Although 'messenger' trips are incorporated in the sample takers described, other trips could be used with this type of sample taker.)

2 (*a*). **The Slow Displacement Type—Piston Controlled,** Fig. 2 (*a*).

Whilst running in, the position of the cylinder relative to the piston is as shown in the sketch, the cylinder being held in this position by the pin. The space above the piston is filled with water so that any leakage past the piston when running in will be of water and not of crude.

After a given time, when the desired depth has been reached, the pin is withdrawn by means of the spring-loaded trigger which is tripped by a clock-controlled electro-thermic device. (The latter depends on the melting of a fusible alloy by means of a small heating element, the current to which is furnished by two small accumulators, carried in a separate pressure-tight container immediately above the sample taker.) The cylinder then falls slowly past the piston, and the sample is drawn into the space thus formed below the piston head through the non-return valve, which then seats by its own weight. The positive valve remains closed throughout, being for use on return to the surface, when the non-return valve is plugged off. This type of sample taker is described in detail by Pym [16, 1933].

Advantages:

(*a*) No risk of contamination of sample.

(*b*) No pressure reduction on sample whilst entering the sample taker.

(*c*) Prevention of valve leakage is easy, as small valves can be used and are located at the lower end of the sample chamber.

(*d*) Positive trip.

Disadvantages:

(*a*) Weight too great to run on piano wire, owing to mechanism and the accumulators.

(*b*) Electro-thermic trip requires very careful adjustment to ensure success.

(*c*) Possibility of leakage past the piston-head, which is difficult to prevent with certainty owing to the size of the joint between the upper face of the piston and the shoulders against which it seats when the sample has been admitted.

2 (*b*) **Slow Displacement Type—Pressure Controlled,** Fig. 2 (*b*).

When running in, the upper section of the sample taker is full of mercury, which is maintained in it by means of a positive gas-pressure in the lower section, acting on the surface of a seal of mercury in it covering the bottom of a tube connecting the two sections.

The gas-pressure initially applied at the surface in the lower section is adjusted to that at the depth at which the sample is required to be taken—temperature increase in the well being allowed for. When this is exceeded crude slowly enters the bicycle tube type non-return valve, forcing mercury back into the lower chamber and compressing the gas in it.

The size of the sample collected is determined by the additional depth to which the sample taker is lowered. This type of sample taker has been described in detail by May and Laird [14, 1934].

Advantages:

(*a*) No pressure reduction on sample whilst being admitted.

(*b*) Small valves possible.

(*c*) Being under positive pressure there can be no loss of dissolved gas, even if there is a leak. A large leak results in total ejection of the sample.

(*d*) Suitable for direct construction of pressure/volume curves without transferring the sample to other apparatus.

Disadvantages:

(*a*) If the saturation pressure increases with depth below the point of admission, any further lowering in order to increase the size of the sample results in the sample being representative of a range of saturation pressures and not of a definite saturation pressure. In practice, therefore, samples are too small for transfer to other apparatus.

(*b*) Weight too great to run on piano wire, owing to the mercury required.

3. **Sudden Admission Type,** Fig. 3.

Before running in, the sample taker is evacuated by vacuum pump through a needle valve at the top of the sample chamber. This valve then remains closed until return to surface. Whilst running in, the non-return inlet valve at the bottom of the sample taker is protected from the well pressure by means of a disk which may be of glass, celluloid, or of soft metal in a suitable housing.

At the desired depth the disk is caused to fail and the sample is admitted suddenly to the sample taker through the non-return valve, which then seats itself by its own weight or by means of a light spring. Failure of the disk may be effected by positive methods, such as by breaking or piercing it by impact on an anchor rod, or by a spring-loaded needle tripped by clockwork. It may also be effected by utilizing the well pressure itself, or by chemical means, e.g. the softening effect of amyl acetate on celluloid. In the two latter methods calibration of disk thicknesses for varying pressures, times, and temperatures is necessary, but if an adequate time factor of safety is allowed these methods are satisfactory. In this type the capacity of the sample chamber must be small compared with the size of the hole, in order that there shall be no pressure reduction on crude not admitted to the sample.

A sample taker of this type is described in detail by Schilthuis [17, 1935], the protecting disk in this instrument being of tin of such thickness as will fail, by creep of the metal, after a given time at the pressure and temperature of the well at the depth at which the sample is collected.

Advantages:

(*a*) Simplicity of design.
(*b*) No possibility of contamination of sample.
(*c*) Small valves, the non-positive valve being at the bottom of the sample taker.
(*d*) Excepting the anchor bar type, is light enough to run two in series on piano wire and light enough also for direct determination of the specific gravity of the sample by weighing.
(*e*) Can be made of much smaller diameter than the other types. Suitable for running in tubing.

Disadvantages:

Gas is evolved from solution from the sample as it is admitted, and the saturation pressure of the sample is, therefore, lowered below that of the reservoir crude.

Such gas can, however, be redissolved by pumping in the mercury or water through the needle valve and agitating the sample taker. When the whole of the gas has been redissolved the sample may then be dealt with as in the case of a sample collected without reduction of pressure.

Application of Data obtained from Bottom-hole Pressure Samples

The scope for practical application of the data described earlier in this article as being obtainable from bottom-hole samples will vary widely from field to field, according to the reservoir conditions. Development problems in limestone fields, where, owing to fracturing, free reservoir connexion and pressure equilibrium may exist over wide areas, even at substantial rates of field production, are entirely different from those in sand fields, where pressure equilibrium may be rapidly disturbed at comparatively low rates of production. In fields where a number of producing horizons are penetrated by the same wells any consistent interpretation of the data obtained is difficult.

In any type of field, however, it is desirable that the data mentioned should be obtained as early as possible in its producing life from wells distributed both laterally and vertically throughout the reservoir. Such a survey combined with a subsequent resurvey after a substantial production has been drawn from the field will indicate the extent to which the potential applications indicated below may be of practical use in the particular field concerned. Fortunately all other data are related to the saturation pressure, so that such a data programme is not so formidable as it sounds. In practice it is only necessary, therefore, to establish the relations between other data and saturation pressure over a sufficient range of saturation pressures for the reservoir concerned, and to confirm that these relations remain constant throughout the reservoir by check determinations in two or three wells located in different parts of the field. (It should be appreciated that it is essential that these relations should be determined from actual bottom-hole pressure samples, and not by regassing dead crude in the laboratory. Results obtainable by the latter method, though very valuable in the elucidation of basic principles, are not directly and quantitatively applicable to reservoir conditions.)

For the remainder of the survey it is only necessary to measure saturation pressures and temperatures—the remaining data being determinable from the graphs already constructed.

The following summary of the potential applications of bottom-hole sample data is only intended to emphasize the practical scope.

In a short article it is not possible to discuss in detail the underlying principles involved, especially as other investigations are intimately connected. Amongst these may be mentioned the measurement and interpretation of bottom-hole pressures dealt with by Pym in another section of this treatise, and flow calculations in the reservoir and in wells from considerations of available energy and energy losses which are dealt with by Beale and May. For fuller discussion of underlying principles the references given against each type of data should be consulted.

1. **Saturation Pressure.** (References: Comins [3, 1933], Pym [16, 1933].)

(*a*) Reservoir energy may be conserved and producing gas/oil ratios reduced to a minimum by limiting the bottom-hole pressure drop of wells on production to the difference between the reservoir pressure and the saturation pressure at the bottom of the hole. The reason for this is that until this difference has been exceeded it is quite certain that no gas will be evolved from crude which is not being produced.

In practice the actual increase in producing gas/oil ratio which results from producing a well at such a rate that this critical bottom-hole differential pressure is exceeded, is dependent upon the reservoir conditions of fissuring and porosity.

In freely fissured limestone fields there is little doubt that the greater part of the bottom-hole pressure drop takes place close to the walls of the hole. Under such conditions, unless the bottom-hole flowing pressure is reduced very substantially below the saturation pressure, the volume of unproduced reservoir crude affected is comparatively small, and consequently the producing gas/oil ratio is not materially affected. The actual effect can only be determined by direct comparison of dissolved gas content with producing gas/oil ratios in individual wells.

Again, in small wells in very tight reservoirs, it may not be economically justifiable to restrict productions sufficiently to control producing gas/oil ratios to the scientific minimum.

(*b*) Estimates are possible of the relative areal productivity in different sections of a field. Such estimates are useful in the early stages of development in allocating the distribution of the production to be drawn from the field to the respective areas and in estimating reserves.

The most productive areas will be those where the saturation pressure does not increase with depth below gas-oil level, and falls, as production is drawn from the field, at the same rate as the saturation pressure at gas-oil level.

The reason for this is that true solution equilibrium can only be maintained throughout the reservoir when the reservoir rock is sufficiently shattered and fissured for convection currents to restore solution as distinct from pressure equilibrium as rapidly as it is disturbed by seepages or production. Diffusion alone is too slow a process. (Under these conditions the saturation pressure is usually the same as the actual gas pressure at gas-oil level, but instances are known, e.g. in East Texas, where the crude is undersaturated.)

Conversely, the least productive areas will, generally speaking, be those in which the saturation pressure of the crude, both before and after production has been drawn, increases with depth below gas-oil level. The qualification is necessary, however, that structure must be taken into

account, convection currents being more restricted in gently dipping sections of a field than in steeply dipping sections. In the former, therefore, an increase of saturation pressures with depth is less significant as an indication of low productivity than in the latter.

In an intermediate category are the areas where, before production is drawn, the saturation pressure is constant throughout the reservoir column, but in which, after a certain production has been drawn, it is found that the saturation pressure below a certain level has not fallen at all. This level is the level at which the reservoir pressure at any given time is the same as the saturation pressure of the crude before production started.

In gently folded reservoirs in which the vertical column of crude between gas-oil and oil-water level is small, there is obviously little scope for this application.

(*c*) In areas where the crude is saturated to full reservoir pressure, the rate of production of individual wells will decline more rapidly than in areas where the saturation pressure falls with the gas-dome pressure. This is because the rate of fall of the gas-dome pressure is always less than that of the reservoir pressure.

(*d*) In any field with copious seepages or with indications of seepages in the past the probability of a water drive is indicated if the reservoir crude is found to be undersaturated. Otherwise the seepages in geological time would have reduced reservoir pressure to saturation pressure. In such fields the rate of decline of reservoir pressures would be very rapid in the early stages of production, if the rate of production exceeded the rate of water encroachment. A sudden check in the rate of reservoir pressure decline and, therefore, in the production decline curves of wells, may be expected when reservoir pressure drops to saturation pressure, as at this point gas begins to be evolved from solution throughout the reservoir. An estimate of when this may be expected to occur is of considerable value in planning the economic development of such a field.

2. **Dissolved Gas Content and Solubility Curve.** (References: Pym [16, 1933], Comins [3, 1933], Lindsly [10, 1933; 11, 1934; 12, 1935], Katz [6, 1934], Morris [15, 1934].)

(*a*) These provide a basis for ascertaining the efficiency with which producing gas/oil ratios are being restricted.

(*b*) Close estimates may be made in advance of actual production of the minimum amount of gas to be separated and processed in the different areas.

(*c*) From the solubility curve, in conjunction with measurements of the specific gravity of gas evolved from solution at different pressure stages, the economic pressure of separation below which it is profitable to process all gas for gasoline recovery, may be determined.

(*d*) The solubility curve is essential to the evolution of any scheme of multiseparation, designed to take advantage of the fact that a larger proportion of the heavier hydrocarbons are so retained in solution in the crude at atmospheric pressure. The economic advantages of such a scheme are very substantial, as it is very much cheaper both in first cost and in operation than normal methods of gasoline recovery from gas evolved from solution.

(*e*) Estimates of the total crude content of the reservoir may be made from the volume of oil withdrawn from the reservoir and replaced by gas evolved from solution as the saturation pressure drops. A knowledge of the position of gas-oil level at dates and of saturation pressures in different sections of the reservoir is necessary to this calculation, but no assumptions regarding structure and porosity are necessary.

Although very speculative, such an estimate provides a useful check on estimates by usual methods, but can only be made after a substantial production has already been drawn from the field.

3. **Shrinkage.** (References: as before, also Floyd and Raider [4, 1935], Brace [1, 1934].)

Provides a basis for correcting estimates of reserves based on porosity and structural data for the difference between the volume of the crude under reservoir conditions and its volume delivered to pipeline. In high-pressure fields the difference may exceed 25%.

4. **Pressure-Volume Curve.** (References: May [13, 14, 1934], Laird [14, 1934], Lindsly [10, 1933; 11, 1934], and separate article by Beale and May.)

(*a*) The proportionate volume of oil to gas and consequently the velocity of the mixture at varying pressures in the producing string of a flowing well can be determined from the pressure-volume curve.

(*b*) The amount of energy per unit volume or weight of crude made available by the evolution of gas from solution and subsequent expansion between the saturation pressure of the reservoir crude and any lower pressure in the producing string of a flowing well, can be accurately calculated from the pressure-volume curve. This has the great advantage over similar calculations based on solubility curves that corrections for Boyle's Law with varying composition of the gas at each pressure stage and corrections for shrinkage of the crude at each stage are unnecessary, these being automatically taken care of in the experimental determination of the pressure-volume curve.

This information is essential to the derivation of formulae for the flow of wells in any particular field. For discussion of the methods by which the losses of energy in the well are calculated or measured, the references given should be consulted.

The main practical applications of such formulae are:

(i) In the design of flow strings.

(ii) In the estimation of production decline of individual wells as reservoir and saturation pressures fall, and of their natural flowing lives under any given producing conditions controllable at surface.

(iii) In determining the scope for checking production decline and increasing flowing lives by reduction of the back pressure at wellheads, due to production lines, &c.

5. **Physical Properties of Reservoir Crude at varying Saturation Pressures.** (References: Jones [5, 1933], Lacey [7, 1934; 8, 1932], Swartz [19, 1931], Katz [6, 1934].)

These data are largely of secondary application, one or more of the physical properties of the crude being involved in most oilfield calculations. The *Specific Gravity* data are perhaps the most important, reliable values being essential to accuracy in calculations of the position of gas-oil and oil-water level—particularly the latter.

The variation which can be effected in the specific gravity of the crude after reduction to atmospheric pressure, by varying the pressure and number of stages of gas separation, is also of considerable economic importance.

Both the specific gravity data and also the *Viscosity* data enter into all flow calculations whether in wells or in the reservoir. In the latter the flow being always viscous, except within a very short distance from producing wells,

the kinematic viscosity is the all-important factor governing migration. The assessment of the increase in specific gravity and viscosity of the reservoir crude which may be expected as a result of decreasing the saturation pressure by production is, therefore, an important factor in deciding whether schemes of gas conservation or repressuring are economically justifiable. (In this connexion it may be noted that Lacey's work on the rate of diffusion of gas in oil has proved that 'repressuring' is only of use if adopted in the early stages of development as a preventive measure, and that it is for practical purposes useless as a means of boosting up the saturation pressure of the reservoir crude once it has been lowered.)

It is a safe generalization that the number of wells required in a given field at a given rate of production will vary directly as the kinematic viscosity of the reservoir crude.

The **Surface Tension** data are of value in that the interfacial tension between the reservoir crude and the reservoir rock influences to some extent the quantity of crude retained in pore spaces above gas-oil level in the reservoir. As the surface tension increases as saturation pressures fall, this factor tends to reduce ultimate recovery.

A number of other factors are, however, involved, and it is a speculative point as to whether ultimate recovery is not actually increased by rapid reduction of saturation pressure. For example, in a very fissured formation with slow pressure reduction, gas may come out of solution from crude in pores by processes of diffusion and the propulsive effect of gas evolution and expansion in ejecting crude from the pores may be lost.

The subject is too involved for further discussion in this article. The practical application will vary with each reservoir, depending on the conditions of porosity and fissuring. Any conclusions based on theoretical considerations can, however, only be speculative until positive data have been obtained regarding the amount of reservoir crude retained in pores at successive stages of reservoir development. Such data could only be obtained from the examination of cores brought to surface under full reservoir pressure.

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SECTION 11

PRODUCTION

PROVED OIL RESERVES

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It has been repeatedly questioned whether estimates of oil reserves are of any practical value, as the greater number of such calculations previously made have subsequently been proved to be grossly inaccurate. But even admitting partial justification for such statements, it must be evident that some idea, however approximate, of the available reserves of essential minerals—petroleum included—is of vital importance in mapping their development and the future trend of the related industries, particularly if it is kept constantly in mind that these estimates are not only never intended as a final word, but must be continually subject to revision in accordance with the changes in their component factors. *The value of these estimates, therefore, hinges on the clear understanding of what is meant by reserves, and that the figures can only apply within the limited time when the controlling factors remain unchanged.*

It should be understood, further, that while estimates of *possible* and *probable* oil deposits are as a rule but idle conjectures, appraisals of *proven oil reserves* can undoubtedly be made with an ever-increasing degree of accuracy. And it is with this in mind that in the present study the endeavour has been to estimate only the world's *proved oil reserves* and to leave out of consideration the questionable volume of the *probable* and *possible* oil reserves.

Such a survey presupposes further a clear distinction between the known amount of oil underground in proved fields at any one time, and the *proved reserves*: that portion which can be economically brought to the surface and made available for utilization.

It should be noted that only a fraction of the petroleum stored underground in proved fields—usually associated with natural gas—is, or can be, economically brought to the surface, that not all the oil brought to the surface is economically utilized; and that, although practically all the natural gas can be economically recovered and utilized, in actual practice a large part of the total volume that reaches the mouth of the well is wantonly blown into the air and wasted. It is thus estimated that in the United States only some 25% of the petroleum stored underground in proved fields is actually brought to the surface; and that in actual practice approximately 25% of the total gas produced is now absolutely wasted. And the dissipation of this gas, unwarranted as it is, not only diminishes the gas supply, but diminishes also the proved reserves of petroleum from such fields as the Panhandle of Texas, where petroleum and natural gas are produced simultaneously.

Many factors affect the estimates of the *proved reserves*, such as the capacity and nature of the reservoir, its depth, the quality of the product, the conservation of natural gas and its efficiency in recovery, the methods of development and recovery, the demand and the price of the crude and its by-products, &c., but superseding at times all of these—in connexion with petroleum and natural gas—is the effect of *subsoil ownership* on the rate and methods of exploitation of the deposits. It should be a comparatively simple matter to eliminate gas and oil waste and over-production, and thereby obtain a maximum recovery and thus increase the proved reserves of petroleum and natural gas, in a field in Russia, Iran, or Iraq, where the subsoil rights are either nationalized, or where an effective legal control of the underground deposits and the manner of their exploitation can be quickly established. It has been, and it is to date, on the other hand, almost an impossible undertaking to regulate intelligently the petroleum and natural gas production in the United States—the largest producer and consumer of the mineral fuels—where the ownership of these products is based on the paramount right of the individual surface owner to *capture*, within the boundaries of his property, all the oil or gas he can, whether or not the oil was originally under his land and regardless of any damage he may do the field by his rate or methods of production. This unlimited *right to capture* has resulted, among other things, in the blowing daily into the air of over 1,000,000,000 cu. ft. of natural gas in the Panhandle field alone, a very high price for the State of Texas and the United States to pay for the sake of perpetuating these antiquated and destructive laws, which place the rights of the individual above community and national rights, and affect national security through the wanton and irreparable destruction of these essential munitions of war. Naturally a change in the rules of ownership and methods of operation might greatly increase the *proved reserves* in the United States without the discovery of new fields.

The world's production of petroleum from the beginning of commercial production to January 1936 aggregates over 27 billion barrels, of which the fields in the United States have produced approximately 60%. Proved reserves on January 1936, on the other hand, are estimated at somewhat under 22 billion barrels, of which the fields of the United States should supply less than 50% under present operating conditions.

These reserves, theoretically, can supply an average total yearly demand estimated at 1,600,000,000 bbl. for 14 years, but in actual practice the discovery of new pools is essential if a shortage is to be averted—particularly in the United States—within a much shorter period. It should be kept in mind that the United States consumption of petroleum and its products now is, and probably will continue for years to aggregate, approximately 60% of the world's total demand.

No one can predict the number, location, or production of new fields. Some, no doubt, will be discovered; in fact, *many must be discovered* in the near future in the United States in order to meet demand without greatly increasing imports.

In estimating the probabilities of these new discoveries one must guard against the oft-repeated assertion to the effect that 'there has been, and there will always be, enough —perhaps more than enough—petroleum to meet demand' even more than against the statement that 'a petroleum famine is imminent'. The writers are of the opinion that the *present proved petroleum reserves*, particularly in the United States, are inadequately small in relation to expected future demands. What the proved reserves will be at any future time is a matter of conjecture.

It should also be pointed out that the proved reserves

outside the United States are as a whole more economically and rationally exploited than in the United States, due largely to the absence in these countries of the detrimental effect of the operation of the Law of Capture. And it seems, therefore, reasonable to assume that the United States will, in the future, depend more and more on foreign fields for its oil supply unless the Law of Capture is to all intents and purposes abolished.

In the United States—by far the most important producer and consumer of petroleum—the rate of discovery of proved reserves in the 5-year period 1921 to 1925 was roughly 820,000,000 bbl. annually, compared with the average yearly demand of 650,000,000 bbl. In the following 5 years the additions to reserves reached the annual figure of nearly 2 billion barrels, or double the average demand of 895,000,000, while during 1931 to 1934 the annual new fields averaged but 580,000,000 bbl., or 290,000,000 bbl. under the amount consumed. It will be seen, therefore, that very important new discoveries are necessary in the near future to compensate for the aggregate depletions.

This illustrates that a table of figures showing proved reserves means little unless such figures are interpreted in the form of declining production from present proved reserves, and such production trend compared to the trend of probable future consumption during a given number of years. Such comparison also gives an indication of the required rate of discovery of proved reserves in order to meet demand. Furthermore, these estimates of *future demand* can be made, if normal conditions prevail, as accurately as the estimates of proved reserves.

Assuming, therefore, a yearly world demand of some 1,700,000,000 bbl. for, say, 10 years to come, we find that present proved reserves of 23,000,000,000 bbl. can only produce about 1,700,000,000 bbl. annually for 1 or 2 years, and that new proved reserves of about 15,000,000,000 bbl. must be developed within the next 10 years.

It is with the above limitations in mind that the authors have compiled the following table showing an estimate of the world's *proved oil reserves*, in which a greater degree of accuracy has been possible in estimating the reserves in the fields in the United States and to a less extent in the Spanish countries than in some of the European and Asiatic fields. Thus the figures of reserves of Iraq are of necessity less reliable than those of Venezuela and Mexico, while the estimates of Russian fields, which are more conservative than official figures, are admittedly but rough approximations.

The foregoing notwithstanding, the figures given are believed to represent as a whole a fairly true picture of the volume of proved oil reserves, and to illustrate that as a whole they are far from impressive and in individual countries like the United States they are inadequately small.

Proved Oil Reserves

(Thousands of barrels)

	Production to 1 Jan. 1936			*Proved reserves 1 Jan. 1936*		
	Field	*State*	*Country*	*Field*	*State*	*Country*
United States	..	..	17,593,200	..	..	10,575,000
Texas	..	4,188,300	..	..	4,250,000	..
East Texas	793,800	..	..	1,331,000	..	..
Conroe	56,600	..	..	550,000	..	..
Yates	209,600	..	..	390,000	..	..
Van	87,100	..	..	268,000	..	..
Others	3,041,200	..	..	1,711,000	..	..
California	..	4,418,900	..	..	4,100,000	..
Kettleman Hills	118,200	..	..	1,412,000	..	..
Midway-Sunset McKittrick	869,800	..	..	162,000	..	..
Ventura	216,600	..	..	133,000	..	..
Long Beach	551,800	..	..	119,000	..	..
Others	2,662,500	..	..	2,274,000	..	..
Oklahoma	..	3,906,100	..	..	700,000	..
Pennsylvania, New York	..	1,002,200	..	..	490,000	..
Wyoming	..	400,900	..	..	230,000	..
Kansas	..	778,700	..	..	195,000	..
Louisiana	..	595,700	..	..	250,000	..
New Mexico	..	96,200	..	..	100,000	..
Others	..	2,206,200	..	..	260,000	..
Russia	..	..	3,364,200	..	..	2,830,000
Iraq	..	..	37,900	..	..	2,475,000
Iran	..	..	641,800	..	..	2,150,000
Venezuela	..	..	1,159,800	..	..	1,350,000
Roumania	..	..	663,600	..	..	633,000
Dutch East Indies	..	..	679,700	..	..	450,000
Mexico	..	..	1,801,500	..	..	420,000
Colombia	..	..	167,500	..	..	275,000
Peru	..	..	184,700	..	..	138,000
British India	..	..	253,500	..	..	111,000
Argentina	..	..	138,000	..	..	92,000
Trinidad	..	..	115,400	..	..	91,000
Others	..	..	499,200	..	..	375,000
			27,300,000			21,965,000

SCIENTIFIC UNIT CONTROL

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THE term 'Scientific Unit Control' as used in Petroleum Technology means the application of a systematic and formulated method of extracting oil (and/or gas) from a natural reservoir. Such a reservoir is usually referred to as a pool or field, and is the obvious unit for this operation.

In order to trace the growth of scientific unit control of oilfields it is necessary briefly to review production methods since the exploitation of petroleum deposits began on a commercial scale. As is well known, the first well which had this for its sole objective was drilled in Pennsylvania in 1859, and since this date over 60% of the world's total production has come from the United States, which country has in consequence been at all times the standard of reference in all matters connected with the oil industry. Except when other countries are specifically mentioned, therefore, it should be understood that throughout this article reference is being made to conditions in the U.S.A.

The history of production methods can be conveniently divided into three periods:

First period	1859–1913
Second period	1913–26
Third period	1926–35

First Period, 1859–1913.

When petroleum was first exploited commercially the accepted position in most countries regarding the ownership of minerals was that they belonged to the owner of the surface of the ground. This was fairly satisfactory for solid minerals, but it was not realized immediately how extremely unsatisfactory it was for such migratory substances as oil and gas, which could be caused to flow underground from beneath one surface property into a well drilled by a neighbour.

In 1889 the Supreme Court of Pennsylvania in a decision on this matter held that petroleum, being a fugitive substance, could be likened to wild game, and on this analogy it was ruled that oil and gas became the property of the captor. This legalized the competitive development and operation of reservoirs in sections dictated by surface ownership, allowing each owner to seize as much oil as possible before his neighbours could obtain it. Similar conditions also arose in other oil-producing countries in which the land was held by a multiplicity of owners. (In actual practice the landowner very rarely exploited his own property, but leased the oil rights to an operator in return for a royalty on the oil produced.)

The guiding principle of development was to obtain as much oil as possible in the shortest space of time. Speed of drilling therefore became the greatest essential, and technical progress was for many years centred on this one operation, no attention whatever being given to the effect of such a policy on the ultimate amount of oil obtained. In effect, the driller was in sole charge of production methods.

Oil as it exists in the reservoir is usually saturated with gas at a considerable pressure, and in some pools gas also exists in the free state above the oil. To the driller gas in an oilfield was a nuisance and a danger, a substance to be vented to the atmosphere and got rid of as soon as possible. In very few instances was it a saleable commodity, for it could not be stored, whereas oil could be run into tanks. The more gas there was associated with the oil the higher was the pressure in the well, and to the driller the obvious thing to do was to allow the well to produce at a high rate until the pressure declined to manageable proportions. Sometimes a well entered a gas-filled zone through which it was impossible to drill for the oil below; in these cases the well was allowed to flow wide open in the hope that some oil would be produced. Frequently this was successful, and in consequence it became an established practice, but colossal amounts of gas were wasted in comparison with the small amounts of oil obtained.

It must be remembered, however, that in many cases it was probably impossible to restrict the initial flow of wells owing to the lack of suitable high-pressure equipment, but if the demand for this equipment had been sufficiently insistent, there is no doubt but that it would have been forthcoming.

One of the earliest occasions on which attention was drawn to the enormous wastage of natural gas taking place in the petroleum industry was in the United States Geological Survey Bulletin no. 394, published in 1909. The wastage, which was estimated to be at the rate of about 1,000,000,000 cu. ft. per day, was attacked on the grounds that it was a direct loss of mineral resources; no mention was made of the possible effect the production of this gas might have on the recovery of crude oil.

As speed was the main consideration in the development of a lease on an oil-pool, economy could only take second place. Sound engineering methods were conspicuous by their absence, being supplanted by hasty improvisations.

The production of oil from a new field rapidly reached a peak value, and almost as rapidly declined. Oil pipeline and storage systems had to be installed to meet the peak, and these were soon far in excess of requirements. Frequently the storage provided consisted of earthen reservoirs and open tanks from which the losses by evaporation were of considerable magnitude, but, of course, of no great value until the advent of the internal-combustion engine. These open tanks constituted a very serious fire risk, and fires were of frequent occurrence.

Transportation difficulties were also a source of considerable loss, for the roads in existence in the vicinity of a newly discovered field were usually totally inadequate and in the winter were to all intents and purposes impassable.

As a result of the great variations in the supply of oil which followed the discovery of each new pool, the market suffered from alternate periods of under- and over-production. The smaller fluctuations were smoothed out to some extent by the enormous stocks of oil held by the refineries, but the price for crude reacted to every variation. At no time, however, did the price of crude ever fall below the cost of production, which is perhaps unfortunate, as such an event would have focused attention on the inefficiency of production methods at an earlier date.

As mentioned previously, attention was drawn to the waste of natural gas entailed by the production of petroleum in 1909, but the event which clearly marked the end of the period was the formation of a Petroleum Committee by the American Institute of Mining Engineers in 1913. Trained engineers began to turn their attention to the problem of oil production, and the importance of the subject was emphasized by various Universities instituting courses of instruction in petroleum geology and petroleum engineering.

The importance of the application of science to the industry was similarly marked in England by the institution of a degree course in Petroleum Mining at the University of Birmingham in 1912 and the foundation in 1914 of the Institution of Petroleum Technologists.

Second Period, 1913–26.

In 1913 an interesting application of the use of gas in an oil sand was developed by I. L. Dunn at Marietta, Ohio. This process, at first called the 'Marietta' process, but now usually referred to as the 'gas drive', consisted in the injection of gas or air into an oil sand from which practically no further production could be obtained by the ordinary methods. By careful selection of an injection well it was found that the gas displaced oil from the pores of the sand and pushed it into suitably situated producing wells.

The application of science to the production of oil was seriously retarded during the War years, 1914–19, owing to the fact that no organized research on the subject was carried out.

In spite of this, by 1916 engineers were beginning to realize that natural gas which was produced with oil was not only a valuable fuel, but that it provided the energy for the expulsion of the oil from the reservoir. The measurement of gas/oil ratios followed in the course of the next few years, and it was found that these varied with the rates at which wells produced. It became clear that the oil in the formation carried a fixed amount of gas in solution, and that gas produced in excess of this quantity came from oil which remained in the sand. There was, therefore, every possibility that this oil, having been deprived of some of its gas, might no longer possess sufficient energy to cause it to flow into a well.

In order to obtain a maximum recovery by natural forces the obvious solution was to adjust the rate of production from a well so that the producing gas/oil ratio was a minimum.

During the period under review attention was also directed to the use of water for the displacement of oil from sand. For many years water had been regarded as the chief enemy in an oilfield, and in most countries legislation existed which required all water-shows encountered in the drilling of wells to be effectively isolated from the oil reservoir. Some of the earliest laboratory work on the movement of water in oil sands was carried out by R. Van A. Mills of the U.S. Bureau of Mines in 1920, and it was shown that if the water was carefully controlled, the oil could be recovered by this means, but that unless the sand was of fairly uniform permeability there was a risk that oil might be trapped in the finer grained portions of the sand.

The great example of this process is in the Bradford field of Pennsylvania, where water flooding as a production practice was legalized in 1921.

In 1926 Beecher and Parkhurst published the results of their investigation (which was initiated by H. L. Doherty) into the effect of dissolved gas on the physical properties of crude as it exists in the reservoir (Petrol Dev. and Tech. in 1926 A.I.M.M.E. 51). They found that the more gas there was in solution the lower was the viscosity and the surface tension of the oil, and consequently the more easily could it be extracted from any porous formation in which it was held.

This at once suggested that it was most desirable that the gas-pressure should be maintained in an oil-pool in order to keep as much gas in solution as possible, and it also provided a further reason for keeping producing gas/oil ratios down to a minimum.

Towards the end of the period under consideration it thus became clear that if the greatest benefits were to be obtained from the application of scientific methods to the production of oil, the development and operation of each pool must be carried out under one management.

In 1926 the U.S. Federal Oil Conservation Board issued a report in which they recommended the adoption of unit operation in the development of individual oil-pools. This official recognition of unit control may be taken as the culmination of 13 years' progress in the application of scientific principles to the production of oil, and marks the end of this second period. Progress had by no means come to an end, but the framework of scientific unit control had been built, and the work which remained to be done consisted largely of filling in the details.

Third Period, 1926–35.

The principle of scientific unit control was readily accepted by the petroleum industry, for it is the only logical method of economic exploitation. This third period should therefore have seen the application of the method to every new oil-pool as it was discovered. Unfortunately this was not the case, for in many oil-producing countries the existing system was so firmly established that only legislation could change it, and the framing of such legislation has up to now presented too many difficulties.

In those countries where petroleum is the property of the State, or where concessions covering large areas are in the hands of single interests, unit control is invariably practised. In the former category we may instance the U.S.S.R., and in the latter the best-known examples are the fields of South-west Iran and the Kirkuk field in Iraq. It is indicative also of the importance with which unit control is regarded that in Great Britain, where petroleum has not yet been discovered in commercial quantities, the Petroleum (Production) Act of 1934 contains a clause whereby unit development may be enforced 'in order to secure the maximum ultimate recovery of petroleum and to avoid unnecessary competitive drilling'.

In 1927 there began in the U.S.A. a period of overproduction of a magnitude never before experienced, one result of which was to stimulate interest in the recently enunciated system of unit control, not so much on account of its general desirability, but because it offered the particular advantages of reduced production costs and the possibility of regulating the supply of crude to market requirements. At this time about fifteen pools in the U.S.A. were being operated as units, but their combined output was negligible compared with the total from the whole country, and therefore had no influence on the general situation. In these instances unit control was achieved by the various persons interested in each pool coming to a voluntary agreement regarding development and operation, but in

the majority of fields such co-operation was clearly impossible owing to the number and diversity of interests involved.

Over-production, therefore, continued until the situation was so serious that each of the individual oil-producing States of the U.S.A. took steps to control it. This they accomplished by various systems of proration, which means the limitation of the amount of oil produced. The quantity is based in some cases on the open-flow capacity of the wells, in others a fixed quantity per well is allowed, while in some it is calculated from various factors which take into account reservoir volumes and pressures. These methods of limiting production must not be confused with scientific unit control, although in a few well-known cases they have to all intents and purposes led to this result.

The Advantages of Scientific Unit Control

Most of the advantages conferred by this system of oil-field exploitation are apparent in the foregoing historical survey of the industry. They may be summarized as follows:

1. The ability to apply production methods that will result in the maximum ultimate recovery of oil from a reservoir.
2. The elimination of periods of over-production, with the consequent stabilization of crude-oil supply and prices.
3. The ability to estimate with a fair degree of accuracy the amount of recoverable oil remaining in a pool.
4. The removal of the necessity for the storage of large quantities of crude on the surface, since the oil-pool itself now provides the reserve storage capacity. In addition to the saving on tanks, evaporation losses and the risk of loss by fire are much reduced.
5. The reduction of production costs to a minimum by:
   - (*a*) Avoiding the drilling of unnecessary wells.
   - (*b*) Maximum utilization of natural energy for lifting the oil to the surface.
   - (*c*) Avoiding a high initial peak in the off-take from a pool, thereby obviating the need for a large surface-plant capacity which would only be in use for a short time.
   - (*d*) The development of each field in an orderly methodical manner on sound engineering principles, so avoiding the waste which invariably ensues when work is carried out against time.
   - (*e*) Avoiding a peak demand on services such as roads, water-supply, and staff accommodation.
   - (*f*) Operating to a carefully prepared and settled programme.
6. A reduction in the hazards of the industry, e.g. wells have on occasions got out of control owing to the desire to secure completion before a competitor, and in attempting to do so unnecessary risks have been taken. A well, if out of control for some time, may easily damage a whole pool.
7. Research work on reservoir conditions and methods of operation is facilitated.
8. The improvement in the living conditions of development and operating staff employed on a field remote from the amenities of civilization.

The Application of Scientific Unit Control

I. Properties of Reservoirs.

Petroleum is widely distributed throughout the world; in fact it is almost impossible to name any part of the earth's surface in which it is not found, but it is only when it is concentrated in sufficient quantity to warrant exploitation that it assumes a commercial value.

The common strata in which oil and gas are found are sandstones and limestones, as these two rocks usually possess the first two essential properties of a reservoir, permeability and porosity. In all there are four essentials for a concentration of petroleum:

(*a*) A permeable stratum into which and from which oil and gas can flow.
(*b*) A porous stratum which can provide storage space.
(*c*) A geological structure of such a shape that oil and gas collect in one zone and form a concentration.
(*d*) A cap-rock which prevents further upward migration.

Of these four requirements permeability is of most direct importance in the production of oil and gas from a reservoir, because it is on this property that the extraction of the oil depends. For a long time this fact was not fully appreciated, and on this account it will probably not be out of place to discuss this property at some length.

The importance of porosity has at all times been recognized, and there is therefore no need to dwell on this point, or on items (*c*) and (*d*), both of which are too obvious to require further comment. In the following pages it will be assumed for the sake of simplicity in discussing reservoirs that they consist in every case of a single-producing horizon. Such, of course, is not always the case, and where there is more than one horizon careful judgement is required in deciding whether to treat them as one reservoir or to develop them separately. Generally speaking, it is safer to treat them as separate pools, but to develop them concurrently.

(*a*) **Permeability.** (1) A measure of the permeability of a material may be obtained by taking the volume of liquid of unit viscosity which flows per unit of time through unit cross-sectional area for unit pressure drop per unit of length. In c.g.s. units this becomes c.c./sec./sq. cm./dyne/sq. cm./cm.; instead of a pressure gradient of 1 dyne/sq. cm./cm. Wyckoff, Botsel, and Muskat of the Gulf Research Laboratories in Pittsburgh suggested a gradient of 1 atm. per cm., and proposed that the unit of permeability so obtained be termed a 'darcy'. As this unit proved to be a rather large one for the majority of substances, it has been subdivided in the usual decimal manner so that the term which is now coming into general use is the 'millidarcy', equal to one-thousandth of a darcy.

(2) For any given porosity, permeability may vary between the widest possible limits, i.e. from being non-existent to permitting the flow of fluids with the utmost freedom. The extreme values are more normally found in limestones, the lower limit being in very fine-grained rock, and the upper limit being due to the existence of large connected cavities and fissures.

(3) The permeability of sandstone is much more intermediate in value. The Bradford field (Pennsylvania) may be taken as a good example of a fine-grained sandstone, in which the porosity in general ranges between 11 and 13%, with a variation in permeability from 2·0 to 5·0 millidarcies. The sand of the East Texas field probably possesses greater permeability than any other sandstone formation, ranging as it does from 350 to 3,000 millidarcies, the greater part of it being near the latter figure, with porosities from 22 to 28%. (The above porosities and permeabilities of sandstones have been taken from the paper 'Physical Tests and Properties of Oil and Gas

Sand' by Fancher, Lewis, and Barnes in the *Proceedings of the World Petroleum Congress*, London, 1933, to which reference should be made for further information on the subject.)

(4) It is clear from the figures quoted that there is no relationship whatever between porosity and permeability, and that it is possible for a rock to possess a very high porosity, and yet have such a low permeability that the oil is practically unrecoverable. Porosity is usually measured as a percentage of the total volume of a sample; it is not concerned with the dimensions of the individual pore spaces, but only gives the sum of their volumes. Obviously the smaller these minute openings in the rock, the greater will be the resistance they will offer to the flow of a fluid, in spite of the increased number necessary to maintain the same porosity. Permeability, therefore, depends on the texture of the reservoir rock, which, in the case of a sand, is a function of the dimensions of the grains and the amount of cementing material which may be present.

(5) Although permeability in itself is essential for a concentration of oil to be of commercial value, it is its variation from point to point in the reservoir rock which is of importance when considering the methods to be employed for the extraction of the oil from the formation.

Both sandstones and limestones, being sedimentary rocks, consist of thin layers which frequently differ considerably in texture, and therefore in permeability. This variation in permeability is further accentuated in limestones by the existence of fractures and solution channels, and in sandstones by varying degrees of cementation.

The movement of fluids in a reservoir is caused by pressure differences, and the greater part of the flow will naturally take place along the paths of least resistance, i.e. through the zones of highest permeability.

II. The Extraction of Oil from Porous Rocks.

There are five processes available for the extraction of oil from the porous rocks of a reservoir and its delivery into producing wells. They are:

(*a*) Gravitational drainage.
(*b*) The release of gas from solution.
(*c*) Displacement by water.
(*d*) Gas drive.
(*e*) Water drive.

The first three may be said to be natural and the last two artificial processes.

(*a*) **Gravitational Drainage.** As far as drainage vertically downwards is concerned gravity is effective in all formations except those of the lowest value of permeability. For uniform drainage the overall rate of withdrawal should not exceed the rate attained in the zones of least permeability.

An effect which must always be considered in conjunction with drainage by gravity is capillarity. This is controlled by the surface tension of the oil, and the smaller the interstices in the rock, the greater is the capillary height. In a very fine-grained formation the conditions may be such that capillarity almost entirely prevents gravitational drainage.

The surface tension of the oil also controls the thickness of the film which adheres to the solid material with which it is in contact. In a porous material the surface in contact with the oil may be very great indeed, and a small decrease in surface tension will result in an appreciable increase in the amount of oil recovered.

In order to keep losses due to capillarity and adhesion to a minimum, therefore, it is necessary to maintain the surface tension of the crude at as low a value as possible, and this can only be achieved by keeping all dissolved gas in solution.

Although the force of gravity is sufficient to cause drainage vertically downwards through rocks of ordinary permeability, it is unable to overcome the resistance which exists in the immediate vicinity of the producing wells. As the flow of oil converges to these exits its velocity, and therefore the friction losses, increases rapidly, and only in the most permeable formations can a reasonable production rate be attained without assistance from some other source of energy. Here again, however, by keeping all dissolved gas in solution, the viscosity of the oil remains at its lowest possible value, and a minimum of assistance will be required.

(*b*) **The Release of Gas from Solution.** In every commercial accumulation of oil there is a considerable quantity of gas present in solution. This gas imparts to the crude a vapour pressure, or saturation pressure, which is the point at which the gas begins to come out of solution when the pressure on the oil is reduced. The gas so released makes its appearance in the form of very small bubbles, which increase in size as the pressure continues to fall. If the oil completely fills a porous medium when this happens, a portion of it is forced out in the direction from which the pressure reduction has come.

The interstices in the rock are not of uniform diameter, and may therefore be considered as a series of minute chambers connected by narrow passages. As the movement of oil in the direction of the pressure gradient continues, each small bubble is carried along until it reaches a connecting passage which is not large enough to permit further progress.

A small bubble is a very rigid structure, and considerable force is necessary to distort it. The result is that the bubble closes the entrance to the passage and prevents any further movement of oil or gas in that particular direction until sufficient pressure grows up behind to force it though. This action of gas bubbles is known as the 'Jamin Effect', and leads to the existence of a pressure gradient without flow. If flow is to be maintained, a steadily increasing pressure gradient is required, but this is limited to a maximum value by the saturation pressure of the crude, and a time comes, therefore, when there is no further flow. In effect the formation is 'gas-locked'.

Generally the pressure gradient is due to a well being opened to production, and as its rate of flow declines the back-pressure on the formation at the bottom of the hole is reduced. The difference between this and the original reservoir pressure provides the pressure gradient, which in a sandstone field spreads its influence over a steadily widening zone of which the well is the centre point. Ultimately the pressure gradient can no longer be increased and production from the well ceases. On the fringes of the zone affected the reservoir pressure is unchanged, but in the well the pressure may have been reduced to atmospheric or even lower. Each well, therefore, under these conditions, possesses a limited sphere of influence.

It has been found by actual experience that the adjustment of the back-pressure at the bottom of such a well has a considerable influence on the total amount of oil produced. If a steep pressure gradient is maintained, the gas/oil ratio of the well is usually higher than if a gentler gradient is employed. This appears to be due to the bubbles of gas

escaping ahead of the oil when the rate of flow exceeds certain values, with the result that an increased amount of oil remains in the porous formation.

The release of gas from solution therefore provides a means of expelling oil from porous rock, but by reason of the Jamin effect and the fact that gas can escape ahead of the oil from which it has been evolved, the process is very inefficient. It is generally accepted that not more than 20 or 25% of the total oil in the sand is recovered by this process.

(*c*) **Displacement by Water.** Many oil-pools are subject to a hydrostatic pressure from edge-water. This pressure is usually derived from a fixed water table and is constant in value at any point within the water column. As oil is withdrawn from the reservoir the water forces its way in. It was shown by the experiments of R. Van A. Mills (mentioned earlier in this article) that there is a tendency for encroaching water to travel through the more permeable zones and isolate oil in the less permeable ones. Large quantities of oil may be completely lost in this way.

As the water rises in the formation the pressure it exerts on the oil is steadily reduced by the difference in density between the oil and water columns. If the oil is fully saturated with gas, this reduction in pressure results in the evolution of small bubbles in the pores of the rock, and gas-locking similar to that described in (*b*) above may arise. Although in some cases this may be desirable in order to increase recovery, in others it may lead to a loss of oil. Under suitable conditions and where the encroaching water is carefully controlled it appears that the recovery of oil by this process is very high.

(*d*) **Gas Drive.** In an earlier paragraph reference was made to the Marietta or gas-drive process. Initially it was developed to extract more oil from fields in which the limit of recovery had been reached by the then existing production methods. The logical extension of the process was to apply it much earlier in the life of a pool, and one of the first to be treated in this way was the Dominguez field in California. Even in this case, however, the field had been producing for 3 years before gas drive was applied. A later example is that of the Sugarland field in Texas, to which the process was applied within a year of oil being discovered. This field also illustrates a variation in the method of application. Instead of gas being injected into a well to drive oil laterally into an adjacent well, in this case the gas was injected into the crestal portion of the structure in order to maintain pressure above the crude and to prevent, as far as possible, the evolution of gas from it. In effect, therefore, the injected gas is driving downwards, and instead of its sphere of action being limited to the formation between adjacent wells the whole of the field is being uniformly subjected to the process.

The advantage of this method of application is that the gas drive is acting in the same direction as gravitational drainage, and there is less likelihood of the gas following an easy path along a streak of high permeability sand and so leaving oil behind in the less permeable formation.

(*e*) **Water Drive.** The employment of the water drive as a process has received considerable attention since its success on a large scale in the Bradford field. The more usual method of application is for the water to drive the oil laterally into a nearby producing well. Where there is considerable variation in permeability there is a danger, as with natural water encroachment, that large quantities of oil may be trapped and become unrecoverable. As a consequence this process is most successful in reservoirs in which the permeability is fairly uniform.

From every point of view, therefore, whether of viscosity, surface tension, or Jamin effect, all the gas which naturally occurs in solution in the crude should, if at all possible, be maintained in that state until the oil enters a well.

III. The Development of Production Scheme.

Owing to the great variations in the conditions under which concentration of oil occurs in commercial quantity, no uniform method of production can be applied to all fields.

There are, however, three general principles which should be followed if the construction and permeability of the reservoir permit. They are:

(*a*) That the oil should enter the wells without any free gas.

(*b*) That if a gas zone forms in the crest of the structure the withdrawal of oil should be so distributed that the gas-oil contact falls uniformly over the whole field.

(*c*) That if edge-water is present, the withdrawal of oil should also be so distributed that the oil-water contact is maintained horizontal, no matter whether it is stationary or rising.

Unfortunately many reservoirs do not lend themselves readily to the application of these principles, the main difficulty arising from the shape, particularly when it is lenticular. In these cases (*b*) and (*c*) cannot be applied.

Considering the normal dome-shaped structure, however, the only case in which special treatment is required is when the permeability of the formation and the viscosity of the oil are such that gravitational drainage can only take place so slowly as to be practically non-existent.

In the majority of fields the reservoir pressure and the saturation pressure of the oil are practically identical, and it will be necessary to supply the bottom-hole differential pressure artificially. This can be carried out by injecting gas (or air if gas is not available) into the highest part of the reservoir, and operating what is in effect a vertical gas drive.

It will be realized that even for the application of these general principles a considerable amount of information is necessary, and it is obvious that the more information there is available about a reservoir when the method of production has to be decided upon, the more successful will be the results.

The discovery of a new pool should therefore be followed by a period devoted entirely to the collection of data. Very rarely has such a procedure been followed in the past, for even when a pool has been entirely under one technical management the production of oil has usually proceeded concurrently with the collection of information, chiefly because the invested capital has demanded a return as soon as it might be obtained. The only instance of which the author is aware in which data has been collected before the production of any oil whatever is that of the Kirkuk field in Iraq.

Here development had to proceed to a state of sufficient knowledge before the 1,150 miles of pipeline across the desert to the Mediterranean could be warranted, following which another 2 years were available before production began. By this time very little further progress could be made without production taking place.

The following information regarding the field should be collected before the withdrawal of oil in commercial quantities begins.

(*a*) **The Size and Shape of the Reservoir.** This will be accomplished with as few wells as possible, but it is usually possible to fit them all into the production scheme later on, so that no loss will be incurred in this respect. Where conditions are favourable a geophysical survey may be of considerable assistance.

(*b*) **The Position of the Gas-oil Level.** Very frequently free gas is found to exist in the crestal region of an oil-pool. The approximate position of the gas-oil contact can be obtained by calculation from the observed pressures of a gas-well and an oil-well, and its extent can then be estimated from the underground contour map which will have been constructed from the data collected under (*a*) above.

(*c*) **The Position of the Oil-water Level.** This again may be determined with sufficient accuracy by calculation from the pressure in adjacent oil-wells and water-wells.

(*d*) **The Characteristics of the Oil-bearing Formation.** Every well drilled on the field should core through the full thickness of the oil-bearing formation. The samples recovered should be tested for permeability and porosity, until in this manner a clear picture of the whole reservoir is obtained.

(*e*) **The Physical Properties of the Reservoir Crude.** Bottom-hole samples of the crude should be taken at full reservoir pressure from each of the exploratory wells, and the specific gravity, viscosity, surface tension, and saturation (vapour) pressure measured under reservoir conditions.

From the data gathered under (*d*) and (*e*) the approximate rate of gravitational drainage can be determined, and on this it can be decided whether the general principles enunciated above are applicable or not. If they are, a few tests on actual wells will indicate to what extent gas drive will be required in order to provide a reasonable rate of production from each well. If they are not applicable, then on the information available other methods must be devised; these may take the form of the methods largely in use at the present time, i.e. expulsion by gas expansion, local gas drive, or local water drive.

The application of gas drive at the beginning of the producing life of a pool may appear to be a very expensive process, especially if the rock pressure against which the gas is injected is fairly high (say, 1,500 lb. per sq. in., as in the Sugarland field, Texas). The energy expended, however, is returned in the flowing wells, because the whole of the expansive force of the gas in solution is available for lifting the oil from the bottom of the well to the surface, and artificial lifting methods will never be required (unless, of course, there is insufficient gas present in solution in the first place).

When the broad lines of the production scheme have been decided, the number of producing wells and their spacing can be more or less determined from the off-take required.

In addition to these producers a number of observation wells will be needed in order that a close watch may be kept on fluid movements in the reservoir while oil is being withdrawn. From the information they provide the off-take can be so distributed to maintain the field in fluid balance.

Soon after production begins from a field it is found that some portions of it are far more prolific than others. It is rather an advantage, therefore, for the off-take from the field to increase by a series of steps rather than jump into its full rate at once. By so doing the initial scheme, with a relatively small number of wells, can be extended and modified from time to time as more information is obtained, without loss of continuity or needless expenditure (usually in the form of redundant wells).

Thus it will be seen that the final production scheme must be based entirely on local conditions, but in order that these conditions may be clearly understood it is essential for the whole of a pool to be under unit control.

Scientific analyses of the physical properties of the fluids in the reservoir are necessary in the formulation of the production methods, and a critical examination of all occurrences during production is required in order that they may be correctly interpreted and utilized for the better control of the field.

Such then is Scientific Unit Control.

Conclusion

Past and present methods of operating an oilfield have been briefly reviewed, and the mechanism of producing oil from a reservoir has been examined in broad outline, attention only being given to those principles which are of more general application.

No further arguments are required to emphasize the value of scientific unit control. The case in its favour is so overwhelming that there is no doubt that within a few years all the legal difficulties which prevent its enforcement in the U.S.A. at the present time will be overcome.

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FUNDAMENTAL PRINCIPLES GOVERNING DRAINAGE OF PETROLEUM FROM ITS RESERVOIR ROCKS

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IMPORTANT progress has been made by petroleum production technologists during recent years in attaining a more complete understanding of the manner of occurrence of petroleum in nature and of the physical factors influencing its flow through the reservoir rock into the recovery wells. Systems of well control have been developed and improved; methods of conditioning wells have been devised, which assure more efficient recovery of the drainable oil than has hitherto been possible. The present section affords an outline of the science of oil production, intended to provide a brief review of this phase of petroleum technology and as an introduction to other sections giving more detailed treatment of various recovery methods by other authors.

Lithological Character of Reservoir Rocks

Any study of oil-drainage principles must of necessity begin with an investigation of the lithological properties of the reservoir rock in which the oil and gas is accumulated by nature and through which it must flow in the normal course of drainage to the wells. The lithological properties of the reservoir rock are important in determining storage capacity, resistance offered to flow, the rate at which fluids may enter the wells under the expulsive forces operative, and the percentage of the original oil content that will be retained by the reservoir rock after the expulsive and retentive forces have come into equilibrium.

Common reservoir rocks include semi-consolidated sands, sandstones, and limestones which have percentage porosities sufficiently large and continuous to permit of movement of fluids through them. Shales and clays may contain important volumes of oil, but their pores are usually too small to permit of drainage from them at economic rates.

Among the more important lithological properties of the reservoir rock that must be given consideration are the size and shape of the pore spaces, their continuity and percentage of the total volume of the rock that they represent. In granular rocks the size and shape of the pore spaces will be determined primarily by the size and form of the individual grains, and the resistance to flow will also be influenced by the form of the grains and the nature of the surfaces that they present to the oil. The form of the grains and the nature of their surfaces will vary with the minerals of which they are composed.

Lithological Properties of Sands and Sandstones. Sands and sandstones are composed of mineral fragments of assorted sizes and shapes, which have been gradually fitted together by processes of sedimentation, in a position approaching the minimum possible porosity. In the case of sandstone, subsequent introduction of cementing material between the grains consolidates them into a coherent mass and materially reduces the porosity.

The mineral grains of which oil-bearing sands and sandstones are composed occur in an infinite variety of forms and in all gradations of size from the finest dust particles to coarse pebbles. Their form and surface texture will depend upon the mineral of which they are composed and the amount of abrasion to which they have been subjected. Sand grains are usually angular in shape when first formed, but the edges become rounded off during transportation. In this condition they are described as 'sub-angular' or 'rounded', depending upon the extent to which abrasion has modified the original forms. When an assortment of fragments of such character is slowly accumulated under water, as in the formation of sedimentary rocks, tabular faces of grains will assume similar orientation and be brought into close juxtaposition, and small grains will be deposited in the interstices between large grains. The processes of sedimentation usually develop a well-defined parallelism of the bedding planes, which at the time of deposition are approximately horizontal, but which may later be tilted by folding or faulting of strata.

Porosity of Sands and Sandstones. The percentage porosity, or amount of open space within a unit volume of the reservoir rock, varies within wide limits, tests showing values ranging from 5 to 45%. It is doubtful, however, if porosities above 30% are often attained, and values of from 10 to 25% are more common in commercially productive oil reservoir rocks. A distinction must be drawn between 'absolute porosity' and 'effective porosity'. By the former we mean the total pore space available for storage of fluids, while the latter term refers to that portion of the pore space which is continuous and yields to drainage influences. There are, of course, many cases where a part of the original pore space has been isolated by secondary influence, such as cementation, so that the imprisoned fluids may not escape without actual disintegration of the rock.

The size and shape of the pore spaces of a granular rock will depend upon the size and shape of the sand grains, their arrangement, and the amount of secondary material present on or between the grains. If we conceive of a cast being made of the spaces between an assemblage of closely packed sand grains, and the grains then removed, the form of the pore space thus disclosed would be most irregular. The wider portions of the pore spaces through which flow of fluids would normally occur are circuitous and erratic, and the channels of communication between them are usually slender constrictions that tend to make of each enlargement of the flow channel a more or less rock-walled chamber. Some idea of the size of the sand pores and of the openings between may be gained by considering them to be formed between spherical grains of uniform size. On this basis it may be computed that a cubic foot of unconsolidated sand will contain from 8 million to upwards of 300 million pore spaces, depending upon the size of grains (grain sizes from 10 to 300 mesh). The minimum cross-section of the pore spaces between grains will range from 0·14 sq. mm. to 0·0001 sq. mm. under the same conditions. The grain surface exposed to oil, per cubic foot of sand, will range from 760 sq. ft. to upwards of 25,000 sq. ft.

Lithological Properties of Limestone Reservoir Rocks. Limestone reservoir rocks differ markedly from sands and sandstones in the character of openings that they afford for oil storage and in the influence of these openings on the efficiency of drainage. Openings in limestones are characteristically much less uniform in shape and size than those of sands and sandstones. Limestone porosity is in most cases formed by solution and weathering, and pores are extremely irregular in shape and distribution. They are often much larger than the pore openings of sands and sandstones, and consequently offer much less resistance to drainage. In some oilfields the reservoir rock is apparently made up of calcareous sands, which are formed either as a result of degradation or brecciation *in situ* of former limestone masses. In such cases, though composed of limestone, the reservoir functions as a sand or sandstone reservoir, the oil being subjected to capillary and other influences characteristic of the granular rocks.

Properties of Petroleum and Associated Natural Gases in the Reservoir Rock

Crude petroleum is a mixture of hydrocarbons of highly variable colour, odour, viscosity, density, surface tension, and volatility, and many different hydrocarbon compounds of several different hydrocarbon series may be present.

Among the physical properties of petroleum which influence drainage, the viscosity and surface tension are highly important. Both are influenced by temperature and pressure, and it seems probable that the higher temperatures and pressures which prevail at depth within the earth will make petroleum a product of very different viscosity and surface-tension characteristics than it appears to be at normal atmospheric temperatures and pressures. In the reservoir rock many oils exist at less than half their absolute viscosities at ordinary atmospheric temperature, and, as will be shown below, viscosities are further reduced by solution of large volumes of natural gas at the elevated pressure existing at depth within the earth. Such a condition greatly reduces the frictional resistance offered by the sand to oil movement. The surface tension is reduced by increase in temperature and by increase in pressure. These tendencies are also modified to some extent at elevated pressures by the presence of greater quantities of gas and light vapours in solution in the oil.

Natural gas, which is invariably associated with petroleum in nature, is a mixture of hydrocarbon and other gases and vapours, the properties of which vary widely. The greater part of the hydrocarbon content is generally methane, but smaller amounts of ethane, propane, butane, pentane, and hexane are often present, and in some cases even heptane, octane, and nonane. Methane, the most abundant of the hydrocarbons present in natural gas, is not condensable at temperatures and pressures possible within the reservoir rocks in which petroleum is stored. It is, therefore, always present as a gas, except in so far as it may be dissolved in the liquid hydrocarbons at elevated pressures. Ethane, the second member of the paraffin series, does not become liquid at temperatures in excess of 96° F., and at that temperature requires a pressure of 666 lb. to liquefy it. Both of these conditions are possible within oil-producing sands, so that ethane may exist in either the liquid or the vapour phase. All hydrocarbons of greater molecular weight than ethane have critical temperatures above those reported in most oil sands, so that their liquefaction is only a matter of securing sufficient pressure. Their critical pressures are such as to place them well within the range of influence of pressures developed in deep-seated oil deposits.

The maximum pressure at which natural gas is stored within the earth increases with the depth below the earth's surface, and is considered by many authorities to be an expression of the pressure of the superimposed water column. Pressures of upwards of 3,000 lb. per sq. in. have been recorded in some deep-seated oil deposits.

Studies of the temperature gradient in certain oilfields have indicated an average rate of temperature increase with depth of approximately 1° F. for each 50 ft. Thus where such a gradient exists, at a depth of 3,000 ft. below the surface a temperature about 60° higher than the normal surface temperature might be expected, while at a depth of 5,000 ft. the probable temperature increase would be 100° F. In some deep wells temperatures above the normal boiling-point of water have been recorded.

The physical state of each of the hydrocarbons in the reservoir rock is sometimes difficult of determination. The state of a hydrocarbon substance occurring as one constituent of a natural gas in association with other hydrocarbons will be influenced by partial pressure effects. Dalton's Law holds approximately at low and moderate pressures, but may lead to errors of considerable magnitude if applied to pressures of the order of 2,000 or 3,000 lb. Consideration of the influence of elevated ground temperature on the partial pressure of hydrocarbons will often indicate that certain compounds, such as heptane, hexane, and octane, produced as liquids at the surface, exist as vapours in the formation, even though a high prevailing field pressure would normally produce condensation. In such cases, with high reservoir pressures and temperatures, important readjustments in the physical state of the component members of a hydrocarbon system may occur within the reservoir rock and between the reservoir rock and the surface.

Reduction of pressure as the mixture of gases and vapours is permitted to flow from the reservoir rock to the surface is accompanied by rapid expansion and cooling. Vapours which escape condensation during cooling, undergo great expansion to many times their formation volume. The ratio of volume before and after expansion is a matter of considerable importance in estimating reservoir volumes from surface measurements. Boyle's and Charles' laws governing the expansion of gases hold approximately for low and moderate pressures and temperatures, but may be grossly misleading when applied to expansions from pressures of the order of 2,000 or 3,000 lb. The situation is complicated by the fact that mixtures of gases and vapours do not behave as a pure gas, each constituent influencing the expansion of the others to a certain extent. Deviations from the gas laws of as much as 28% have been noted by some investigators. Apparently natural gas occupies a somewhat smaller volume in the reservoir rock than we might be led to believe by application of the gas laws to the volume of gas delivered at the surface.

Solubility of Natural Gas in Petroleum and Influence of Dissolved Gas on the Physical Properties of the Oil. Natural gas may be present in association with liquid petroleum either in the form of bodies of free gas in the reservoir sand above the general oil surface, as small globules of gas occluded within the oil mass, or in solution in the oil. The solubility of natural gas in petroleum increases as the pressure increases, and such gas as is present will

always be found in solution in the oil up to the limit of solubility at the prevailing pressure. Gas in excess of that necessary to saturate the oil will be present in the free condition, either held within the oil mass or in a zone above the oil surface. Dissolved gas is the chief motivating force operative in expelling the oil from the sand in many oilfields, and the petroleum production technologist is therefore particularly interested in knowing the amount of gas that can be retained within the oil in this form. Investigations have indicated that in some cases as much as 800 cu. ft. of gas are dissolved in 1 bbl. of oil under pressure and temperature conditions existing in certain deep-seated oil deposits.

Increase in the amount of natural gas in solution in a crude petroleum tends to increase its volume and API. gravity. With some oils shrinkage losses as great as 36% have been observed when gas is released from solution by reduction of pressure. Gas in solution in petroleum has an important influence in reducing oil viscosity and surface tension. Under constant temperature conditions, with certain oils and gases, viscosities have been reduced by nearly 60% by saturating the oil with gas at 600 lb. pressure. Surface tension is likewise reduced, in one case by as much as 84%, when oil was saturated with gas at 1,600 lb. per sq. in. pressure.

Expulsive Forces Active in Drainage of Petroleum from its Reservoir Sands

The expulsion of petroleum from its reservoir rock into penetrating wells is due to expanding natural gas intimately associated with the oil, to the hydrostatic pressure of edge-waters, and to gravitational influences. It seems probable that in some cases compaction of the reservoir rock as a result of the weight of superimposed sediments may have some expulsive effect. These forces may operate independently or collectively. In any case, they subject the fluids stored within the reservoir sand to elevated pressures, thus causing movement of the oil and gas through the productive formations towards the lower pressure outlets. This movement is opposed by pore friction, capillarity, and adhesion: resisting influences brought to bear by the reservoir rock on the moving fluids. The magnitude of the resisting force is influenced directly by the viscosity, surface tension, and density of the oil, as well as by the properties of the gas.

The fluids begin their journey through the reservoir rock to the well outlets at the maximum reservoir pressure as determined by summation of the expulsive forces operative; but as they move through the restricted pore spaces of the containing stratum, energy is consumed and the pressure is diminished. The more rapid the rate of flow, the greater will be the energy consumed. The efficiency of petroleum recovery will depend upon the efficiency with which the natural expulsive forces are controlled and utilized.

Expulsion of Petroleum from the Reservoir Rock by Expanding Natural Gas. When a reservoir rock containing petroleum charged with dissolved natural gas under high pressure is penetrated by a well, the equilibrium of forces that previously existed is disturbed. If the well is not shut in and flow of fluids to the surface is permitted, the pressure within the reservoir rock in the immediate vicinity of the well is reduced. Reduction in pressure permits release of a part of the dissolved gas from the gas-saturated oil, and the gas, thus released, assumes the form of minute bubbles distributed through the viscous oil mass. The pressure reduction is greatest at and near the walls of the well, and small gas bubbles first appear in the oil within the wall rocks immediately about the well. Gradually, however, as the pressure reduction extends back into the productive formation in ever-widening circles from the well as a centre, gas bubbles are formed at points more and more remote, until the entire mass of oil within the reservoir rock is laden with myriads of minute gas bubbles. However, they are invariably most numerous in the zone immediately about the well, for here the reservoir pressure has been most reduced.

Since the pore space within the reservoir rock remains constant, it follows that as the gas escapes from solution and the total volume of fluid increases, either a volume of oil and gas equivalent to the volume of the gas formed must be displaced from the reservoir rock, or the gas must find its way through the oil and escape to the well. Such a process of expansion of the fluids would result in a high percentage recovery of the drainable oil, if the gas could be retained within the oil. Unfortunately, however, all the gas does not remain occluded within the oil. On the contrary, it moves with freedom through the oil and through the pore spaces of the reservoir rock to the well outlets. Furthermore, it is not possible to reduce all the gas held within the reservoir rock to atmospheric pressure. Adhesion of oil on the mineral grain surfaces and the capillary drag developed as a result of movement through the rock pores offer substantial resistance to movement and tend to hold the oil stationary within the reservoir rock. Gas bubbles, on the other hand, flow more readily through the pore spaces of the rock, being subjected only to the small film friction at the gas-oil interfaces. Their path through the restricted pore spaces of the reservoir rock is lubricated by thick adherent films of oil, so that the gas bubbles never touch the enclosing rock surfaces. Indeed, it appears likely that the greater part of the oil production of a well during its early life is brought into the well as films enclosing gas bubbles.

Direct observation of the movement of gas-saturated oil through a sand-filled glass tube, with a pressure differential of several hundred pounds between the two ends of the tube, has demonstrated clearly and conclusively that the gas bubbles move much more rapidly through the sand pores than does the oil in which they are suspended. Where most of the gas is released from solution towards the low-pressure end of the sand-filled tube, the oil exists practically in the form of a froth, there being much more gas than oil in the fluid filling the sand pores. Contrary to prevailing belief, the gas bubbles apparently do not grow larger as the pressure is reduced and they approach the outlet. On the contrary, their more rapid rate of flow near the delivery end, due to expansion, causes them to break up into smaller bubbles, the ultimate size of which is probably determined by the size of the sand pores and the rate of movement. Flow near the outlet appears to be distinctly turbulent, though at points remote from the outlet where the pressure gradient is low, and the movement of fluids slow, viscous flow conditions apparently exist. The continuous flow of rapidly moving streams of minute gas bubbles appears to follow well-defined though circuitous channels between the sand grains. The drainage system of a well probably consists of a multitude of such channels, radiating outwards in all directions and perhaps hundreds of feet in length.

Herold [2, 1928] has recalled and extended certain experiments performed by Jamin, an early French

physicist, in which chains of alternating gas bubbles and liquid filaments were forced under pressure through capillary tubes containing occasional constrictions. There is a close analogy between the apparatus employed by Jamin and the channels of intercommunicating sand pores described in the foregoing paragraph, and the conclusions reached in these experiments would seem to have some significance in the mechanics of expulsion of oil from the reservoir rock by expanding gas. Jamin's experiments tended to indicate that in such a series of alternating globules of gas and liquid in irregularly shaped channels of the type described, the gas tends to accumulate in the enlarged portions of the channel, while the liquid is concentrated in the capillary openings between gas bubbles. The walls of the channel remain wet with liquid. Herold believes that a large part of the total pressure loss in moving gas-oil mixtures through the reservoir rock is consumed in deforming gas bubbles, and finds that the pressure necessary to cause movement is roughly proportional to the number of gas bubbles in the channel and to their size and the pressure of the gas they contain. Experiments performed by the author and his associates, however, have indicated that the gas-oil mixture possesses a viscosity so much lower than that of liquid petroleum that it moves with less resistance through the reservoir rock. Gardescu [1, 1930] finds that gas bubbles occluded within a mass of oil are in unstable equilibrium, and that if given sufficient time, the gas bubbles will diffuse through the oil and add to the volume of the larger gas masses trapped at favourable points through the sand. Gas bubbles do not exist within the oil mass before penetration by a discovery well. They are formed and exist within the oil mass only temporarily, as a result of the creation of a pressure differential. They may exist only in supersaturated solution. While much of the oil is carried into the wells in the form of froth—that is, as films enclosing gas bubbles—yet it is probable that the most important function of gas in the production of oil is that of maintaining reservoir pressure, thus causing flow of the oil-gas mixture as though it were a homogeneous mass. This it achieves by its continual release from solution in the oil, and subsequent expansion.

In addition to the effects of dissolved gas in aiding the expulsion of oil from the reservoir rock, large bodies of free gas trapped in the crest of the structure and at other favourable points above the general oil surface will develop an important expulsive effect, due to static pressure from above and behind the oil mass. If properly conserved and not permitted to escape, bodies of high-pressure gas trapped in the structure and allowed to slowly expand may account for a considerable percentage of the ultimate recovery of an oilfield.

Drainage of Petroleum from the Reservoir Rock by Gravitational Influences. At any point within a liquid a hydrostatic pressure exists, which is proportional to the depth below the liquid surface. This hydrostatic pressure exists whether the liquid is in an open receptacle or stored within the intercommunicating pore spaces of a rock stratum. It is conceivable that in a thick or steeply inclined oil sand, without continuous impervious 'partings', the hydrostatic 'head' developed within the oil mass may exert an appreciable influence upon the efficiency of drainage. After the gas associated with a petroleum deposit has been dissipated to such a degree that it is no longer effective in moving oil through the reservoir rock into the wells, a part of the residual oil in the formation will still continue to flow towards the wells by gravitational seepage. The efficiency of gravity drainage may be high under favourable circumstances. If the oil viscosity is low and the sand grains large and permeability of the reservoir rock is high, recoveries of as much as 80% of the stored oil are possible and have been secured under laboratory conditions. Under field conditions, however, a much lower percentage recovery would be the rule. Though these gravitational adjustments are exceedingly slow, often too slow to yield commercial production under present-day market conditions, yet if the walls of the well are maintained free of detrital material and the pores of the reservoir rock are not permitted to become clogged with paraffin or other material impervious to the passage of oil, the recovery obtainable by this means may be an important part of the well's ultimate production.

Expulsion of Petroleum from the Reservoir Rock by Encroaching Edge-water. Everywhere about the edges of most oil deposits the strata which contain the oil are saturated with water, often under high hydrostatic pressure. As the oil and gas are extracted from the reservoir rock, the 'edge-water' encroaches up the dip of the stratum towards the productive wells. This gradual advance of the edge-water towards the crest of the structure has a scavenging effect on the residual oil left within the reservoir rock. Much of the oil held by capillarity is displaced, and, at times, edge-waters contain dissolved salts which apparently have the property of releasing a part of the adherent oil. Oil so concentrated along edge-water lines constitutes an important contribution to the total recovery in some fields.

While edge-waters are often under high pressure, the rate of encroachment is generally slow and the expulsive effects are frequently limited to the immediate vicinity of the edge-water lines. On the other hand, in some fields the hydrostatic pressure of edge-water seems to be the principal and controlling force influencing displacement of oil from the reservoir rock. In such cases the reservoir rock must be highly permeable so that fluids throughout the entire reservoir are responsive to the pressure applied by the edge-water. Water enters the reservoir rock as rapidly as oil is produced in some cases, and the formation pressure instead of declining, as is the case when gas furnishes the expulsive force, is maintained.

A more complex case is presented when considerable gas under pressure accompanies the oil in a field under the influence of advancing edge-water. Here both gas pressure and hydraulic pressure are jointly operative, though one or another may be dominant at different periods of the productive life of the wells. Production of oil may for a time drain the reservoir rock of fluids more rapidly than the water can enter to fill the voids, and reservoir pressure about the wells declines. A brief interruption or restriction in production may allow edge-water incursion to refill the voids and restore pressure.

Expulsion of Petroleum by Compaction of the Reservoir Rock. Some authorities suggest that reduction in volume of the reservoir rock may account for expulsive force brought to bear upon petroleum in the process of drainage. It is thought that release of gas pressure within a high-pressure oil sand may permit readjustment of sand grains under the influence of the great weight of superimposed sediments, to a smaller volume than that formerly occupied, thus expelling a portion of the rock fluids formerly stored within the pore spaces. In support of this theory instances are cited in which surface subsidence has followed release of gas pressure and production of the oil. Considerable sand is produced with the oil in some unconsolidated sand-

fields, no doubt permitting caving of the cap-rock in many instances. While compaction of a poorly consolidated reservoir rock is possible under some conditions, it is considered improbable that any great shrinkage in volume can occur. At any rate, it seems certain that the quantity of oil expelled from the reservoir rock by this means is negligible in comparison with that produced by the other natural forces operative.

Retentive Forces Active in Restricting Drainage of Petroleum from its Reservoir Rocks

Several physical limitations attending drainage of petroleum from its reservoir rocks are responsible for retention of a large percentage of the original oil content of every oilfield. According to reliable authorities, actual recovery by ordinary methods of flowing and pumping is often only 10 to 25% of the original oil content. It is thought that instances are rare in which a larger percentage recovery than 25% is secured from sandfields. The greater part of the oil retained is held within the rock pores by capillarity, and as an adherent film completely enveloping the mineral grain surfaces. In addition, a large percentage of the original oil content probably remains in the reservoir rock by reason of inadequacy or inefficiency of application of the expulsive forces. Resistance offered by the rock pores to movement of the viscous oil is often so great that the effective gas energy available is incapable of causing flow of oil into the wells at a commercially profitable rate. Other forces active in expelling oil from the reservoir rock are also likely to be inefficient in their operation. For example, the hydrostatic pressure of edge-water often produces irregular flooding effects, leading to the trapping of large bodies of oil in fine-grained lenticular sands that become surrounded by water-saturated sands of coarser texture. Gravitational drainage leaves large bodies of oil-saturated sand below the drainage slopes formed within the oil sands above the zone of capillary retention. Proper understanding of the forces and conditions which limit the efficiency of the expulsive forces is essential in the development and application of effective production methods.

Capillary Retention of Petroleum in Reservoir Rocks. Porous solids containing openings of capillary size exert an attraction on liquids with which they come into contact. By operation of capillary force the pores of a sand or rock absorb oil, and the same force resists other forces which may later tend to expel the oil from the rock pores. Capillarity results from the combined operation of three natural forces: the surface tension and cohesion of the oil and the molecular attraction which exists between the oil and the mineral grain surfaces. Oil is drawn into the pore spaces of the reservoir rock as a result of this intermolecular attraction. The surface tension of the oil resists this extension of the oil surface, and cohesion prevents disruption of the oil surface under the influence of the opposing forces.

As a result of capillarity the lower portion of every productive oil sand is left saturated with petroleum; and the thickness of the zone of capillary retention varies with the characteristics of the reservoir rock and that of the oil. When an oil-producing zone, comprising several component sands separated by impervious 'partings' of clay or shale, is drained, each impervious barrier in the formation will become the base for such a zone of capillary retention. The aggregate volume of oil so retained may, under such conditions, be a large percentage of the original oil content.

Retention of Petroleum in Reservoir Rocks by Adhesion. Oils are attracted to most mineral substances by an intermolecular force of considerable intensity. Once brought into contact with the oil, the latter will spread over the mineral surface until the oil is reduced to an exceedingly thin film, or until the available mineral surface is completely engulfed. Of course, in an oil reservoir rock every particle of mineral surface is exposed directly to the oil, and each sand grain becomes completely enclosed within an encasing film. When the reservoir rock is in process of drainage, after all free-draining oil has escaped and the the rock pores have become evacuated of oil to such an extent as may be permitted by capillarity, the mineral surfaces still remain wet with oil. The enclosing film of oil persists because of the cohesive force existing between the oil molecules, which resists disruption of the oil film.

The oil thus retained is not to be thought of as a mere superficial film, but rather as a zone of finite thickness in which the molecules of the liquid interlock or become rooted into those of the solid mineral. It should also be remembered that sand grains, of which the oil reservoir rock is often composed, though small in size, are nevertheless capable of being broken into much smaller fragments, and the minute cleavage planes and fractures along which such subdivision may occur communicate directly with the grain surfaces.

Though the oil films remaining on surfaces of the reservoir rock as a result of adhesion are very thin, the gross amount of oil so retained may yet be large because of the great surface area exposed by the reservoir rock to the oil. Computations indicate that the surfaces exposed for sands of from 20 to 100 mesh range from 1,500 to upwards of 8,600 sq. ft. per cu. ft. of reservoir sand.

Characteristics of Flow of Oil through the Reservoir Rock to a Well

Resistance to Flow of Oil through Reservoir Rocks. Irrespective of the character of the expelling force, whether it be expanding gas, hydrostatic pressure, or gravitational force, movement of the fluids is resisted by: (*a*) friction of the oil and gas on the rock material forming the walls of the flow channels; (*b*) internal friction of the oil in overcoming its viscosity; (*c*) the resistance offered by the gas bubbles to deformation in passing through the restrictions in the flow channels; and (*d*) the capillary drag of the minute openings through which the oil must pass. Consumption of a large part of the energy furnished by the expulsive forces in overcoming this resistance to flow is responsible in no small degree for much of the inefficiency attending oil drainage.

Considering that pressure is applied in varying degree throughout the entire length of each drainage channel, and that energy is consumed in so many different ways in accomplishing movement of the oil, accurate determination of the resistance to flow offered by the reservoir rock becomes a most complex problem. Many efforts have been made to formulate the variables that enter into a determination of the flow resistance of oil through its reservoir rock, but it is doubtful if any one has yet succeeded in developing an all inclusive formula that can be applied with assurance to all types of flow problems.

Radial Characteristics of Flow towards a Well. The rock fluids begin their journey through the reservoir rock to the well outlets at the maximum reservoir pressure, as determined by the expulsive forces operative; but as they

move through the restricted pore spaces of the containing stratum, energy is consumed and the pressure is diminished. Due to the radial characteristics of well drainage, the flow cross-section is continually diminishing as the well is approached, so that the flow velocity must be ever increasing. Also, since the flow resistance increases with the rate of flow, it follows that the rate of pressure loss and the rate of energy consumption are not uniform for each linear foot of distance traversed, but increase rapidly as the well is approached.

At points remote from the well, flow of fluids through the reservoir rock is so slow as to be almost imperceptible. As the fluids move toward the well, the rate of flow through different pressure and sand conditions. Fig. 1 presents a typical pressure gradient for a highly permeable, unconsolidated reservoir sand.

The form of the pressure gradient is determined, for a given sand body and a given oil, by the rate of flow; and this in turn depends upon the field pressure, the proportion of gas to oil, and the viscosity of the oil. The form of the pressure gradient may be influenced in two ways; first, by applying back-pressure to the well, thus reducing the pressure differential and the rate of flow; and secondly, by increasing the well diameter, thus decreasing the flow velocity in the vicinity of the wall of the well. In either case, the result will be a flatter pressure gradient.

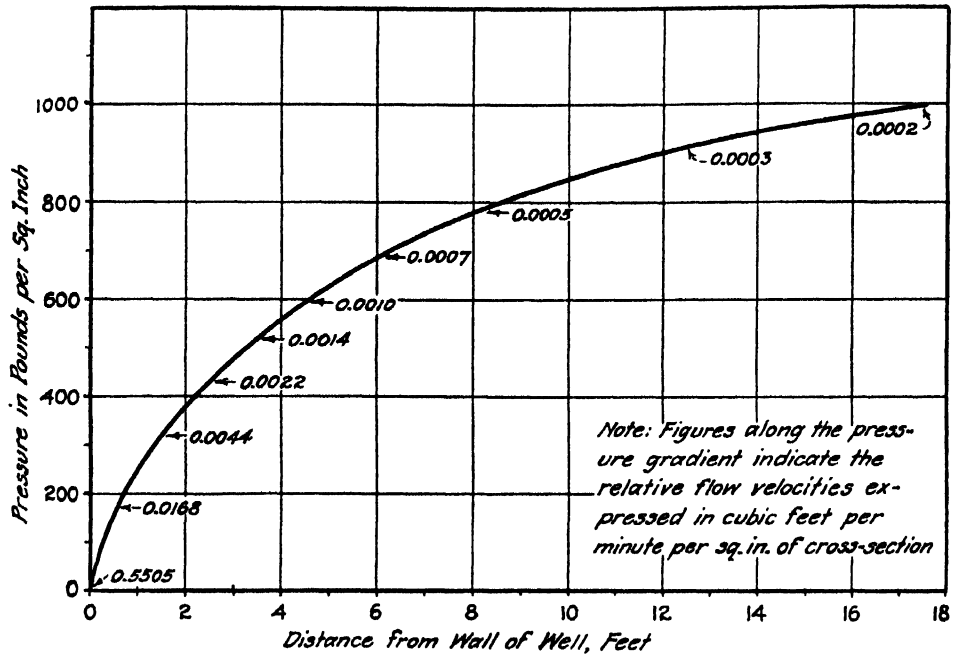

FIG. 1. Pressure gradient within an oil reservoir sand in the vicinity of a high-pressure well.

the reservoir rock increases rapidly, not only because the flow cross-section is diminishing, but because the quantity of fluid is ever increasing. The volume of fluid flowing through the pores of the reservoir rock is increased as it approaches the well by release of gas from solution in the oil. Due to release of gas from solution, the viscosity of the oil must be ever increasing as the pressure is reduced, so that from the energy standpoint, the energy consumption per linear foot of reservoir rock traversed increases even more rapidly, as the well is approached, than the rate of flow. It is evident that a large part of the energy loss in moving oil through the reservoir rock to a well outlet is incurred in the immediate vicinity of the wall of the well.

Pressure Gradient within the Reservoir Rock in the Vicinity of a Well. The pressure gradient within the reservoir rock about a producing oil-well, considered in conjunction with the rate of flow, is a measure of the combined effect of all the many forces and influences brought to bear in moving the fluids through the rock to a well outlet. It is of interest because it is indicative of the rate at which energy is consumed in overcoming rock resistance in different parts of the flow channel, and it provides a measure of the relative efficiency of production by different methods of well control. Knowledge of the pressure gradient within the reservoir rock should also provide a basis for estimating the drainage influence of wells under However, there is a fundamental difference between these two methods of flattening the pressure gradient. When back-pressure is applied to the well the gas enters the well not fully expanded: full advantage is not taken of the natural energy with which the oil is charged. On the other hand, the pressure loss per unit of production is reduced by maintaining the fluid at lower viscosity and volume, and there is less pressure loss because there is less frictional resistance offered by the sand at the lower flow velocity. The overall result, however, may possibly be a lower efficiency of utilization of the gas energy. When the well diameter is increased, the well is operated under the maximum pressure differential, getting the full benefit of gas expansion, and in addition permitting a greater quantity of fluid to flow without increasing the sand resistance. This is because of the greater cross-section of wall area through which the fluids must pass, and partial removal of the 'bottle-neck' about the wall of the well in which so much pressure loss occurs.

The pressure gradient is steeper near the wall of the well because of the greater pressure loss in this vicinity, resulting from the ever-increasing rate of flow as the fluids approach the wall of the well. This is due to the smaller cross-section of the reservoir sand and the increased volume of fluid occasioned by release of gas from solution in the oil as the pressure is diminished. The figures noted along the

pressure gradient reproduced in Fig. 1 indicate the calculated rates of flow of the fluids at different distances from the wall of the well from the particular conditions applying. It will be noted that the fluids are in this case moving 2,750 times as fast at the wall of the well as they are 17½ ft. back in the reservoir sand. Two and one-half feet from the wall of the well the fluids are moving only 1/250 as fast as at the wall of the well.

The Energy Gradient. The concept of the energy gradient as a graphical representation of the rate at which energy is released by the compressed gas during its travel toward the well through the reservoir sand is of interest in studying the drainage influence of wells. As pressure is reduced and dissolved gas is released from the solution in the oil, the volume of gas is continually increasing and at a rapid rate. The consumption of energy between different intervals along the drainage channel may be conveniently compared by computing values for *PV* (pressure times volume) at different distances from the wall of the well. The energy consumed between successive cross-sections of the drainage channel is approximately proportional to the differences between their *PV* values.

Fig. 2 presents a typical energy gradient corresponding to the pressure gradient reproduced in Fig. 1. The energy gradient may be constructed by plotting either the energy consumed per linear foot of travel per square inch of cross-section (curve *A*), or the total energy consumed for the entire flow cross-section per foot of travel (curve *B*). Due to the rapidly changing cross-section of the drainage channel in the vicinity of the wall of the well, curve *A* is much more abrupt than curve *B*. The rapidity with which the gas volume increases is indicated by the figures noted along curve *B*. Thus, the volume of the gas at the wall of the well is 258 times that at a cross-section 8 ft. distant.

It will be noted in Fig. 2 that the rate of energy consumption per linear foot of movement increases rapidly as the wall of the well is approached, while at points remote from the well it is almost negligible. The energy gradient becomes steeper at the wall of the well as the reservoir pressure and the rate of flow increases. The energy gradient is flattened by applying back-pressure to the well, or by increasing the well diameter. Computations based on experimental tests indicate that the energy consumption per unit volume of oil delivered at the wall of the well increases as back-pressure is applied, but is materially diminished by increasing the well's diameter.

Factors influencing Drainage Efficiency

The Gas/oil Ratio as a Measure of Drainage Efficiency. If gas pressure is the principal force active in accomplishing expulsion of petroleum from its reservoir rocks, it follows that methods of recovery that will bring the oil into the well with a minimum volume of gas per barrel of oil and with minimum decrease in the residual pressure in the sand must ultimately be productive of the greatest volume of oil. Each barrel of oil produced is forced into the recovery wells by the expansive energy of a certain volume of compressed gas, originally stored within the pores of the reservoir rock; and each cubic foot of gas, so produced with the oil and expanded to atmospheric pressure, reduces by so much the total energy available for oil expulsion. So important has this relationship between the volumes of oil and gas produced seemed, that petroleum production technologists have come to regard the 'gas/oil ratio', or the 'gas factor', as it is sometimes called, as a measure of production efficiency. The relative efficiencies of different wells producing concurrently in the same field, or

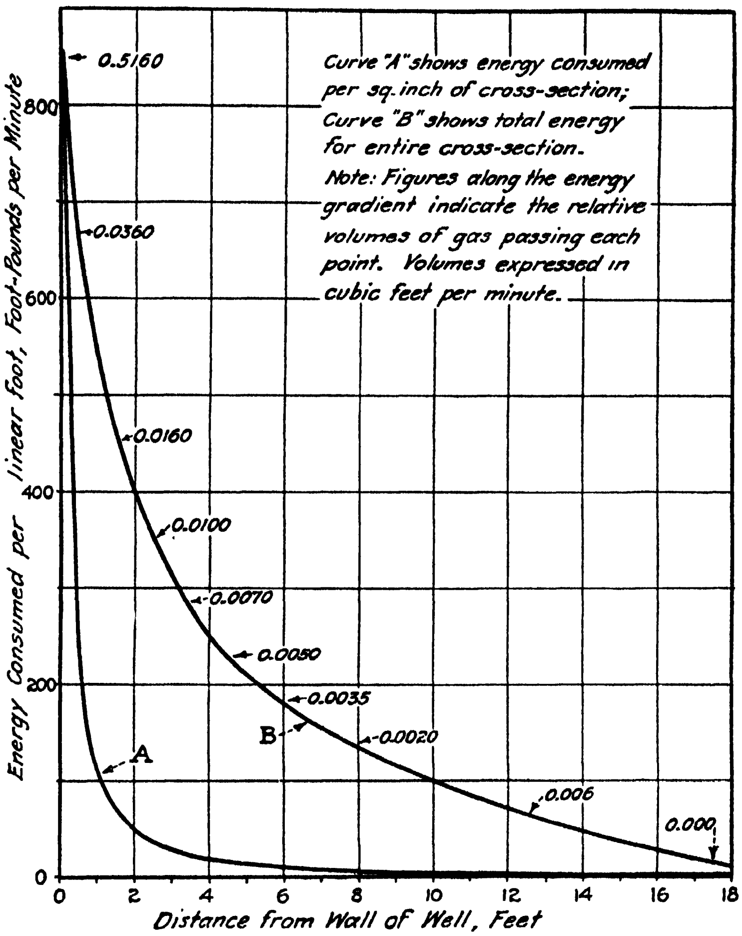

FIG. 2. Energy gradient within an oil reservoir sand in the vicinity of a high-pressure well.

of different methods of well control or systems of recovery as applied to the same well or groups of wells at different times, may thus be compared. Whatever combination of factors within the control of the operator that is productive of the lowest number of cubic feet per barrel of oil is ordinarily adopted as the most efficient.

The gas/oil ratio is commonly expressed in cubic feet of gas, measured at atmospheric pressure, per barrel of oil. Studies made in many different fields show that it is widely variable, ranging from as little as two or three hundred cubic feet per barrel to many thousands. It is immediately responsive to changes in the back-pressure maintained on the productive sands, so that different methods of well control are responsible for wide variations. The method adopted for lifting the oil from the wells also has its influence. For example, formational gas energy is used to lift the oil in the case of flowing wells, while formational gas is called upon to sustain only a part of this duty in

wells operated by gas lift. Formational gas energy is entirely relieved of the burden of lifting the oil in the case of pumping wells. In general, we might therefore expect to find pumping wells producing with lower gas/oil ratios than flowing and gas-lift wells. In some fields edge-water pressure furnishes most of the energy used in driving oil into the wells, and the gas/oil ratio is reduced to the amount of gas actually in solution in 1 bbl. of oil in the reservoir. The age of the wells, or the time that the field has been undergoing exploitation, apparently has its influence on the prevailing gas/oil ratio, the ratio tending to increase as production proceeds. This is possibly due to greater opportunity for by-passing of oil by the gas in the reservoir rock after flow channels have been partially drained, or it may be due, as explained in the next paragraph, to reduction in the prevailing field pressure. The spacing of the wells also determines to some extent the opportunity for gas drainage, closely spaced wells producing with higher gas/oil ratios than is the case with more widely spaced wells where there is less opportunity for extensive gas drainage. The position of a well on structure often has an important influence on the gas factor. Wells near the crest of the structure commonly produce their oil with a higher gas/oil ratio than wells located farther down the flanks.

The volume of gas at atmospheric pressure, which may be produced from a cubic foot of formational gas, is a function of the pressure with which the gas is stored in the reservoir sand. Hence, we may not indiscriminately compare gas/oil ratios in wells producing under widely varying field pressures. If a certain amount of energy is required to force a given volume of oil through the reservoir sand into a well, it is clear that provision of this energy will require the expansion of a larger volume of gas when the field pressure is low than when the gas exists under relatively higher pressure. It is natural that the gas factor should range progressively to higher values as the well ages or as the field is drained of its gas in the normal course of development.

In comparing the efficiencies of different wells, we should be interested not so much in the actual volumes of gas produced with the oil, but rather in the energy consumption represented in the expansion of this gas from the pressure at which it existed in the oil sand. When reduced to the energy basis of comparison, it will sometimes happen, when the efficiencies of two wells are compared, that the one showing the highest gas factor will be producing its oil with a lower unit energy consumption. The author has suggested that a more appropriate basis of efficiency comparison would be the product of the gas factor by the number of times the volume of gas has increased in expanding from the formation pressure to that at which the volume is measured [4, 1927].

The Rate of Production of Oil-wells. The rate at which an oil-well is capable of producing is a matter of considerable interest to the oil producer, inasmuch as his financial return is vitally concerned with the rate of production that can be realized from his property. This, in turn, may often have an important bearing on the development programme, which must often be financed largely out of income received from the production of the early wells.

Many different factors influence the rate at which a well may produce its oil, among these being the permeability and saturation of the reservoir rock, the well diameter and the formation pressure. The yield of a well, producing from a sand or sandstone reservoir rock, is also influenced to an important degree by the thickness of the reservoir rock. The porosity and thickness of the reservoir rock jointly determine its storage capacity, and are therefore of interest in indicating the maximum ultimate recovery obtainable, though not necessarily the rate of production that the wells may achieve.

Research investigations have indicated that the rate of flow increases directly with the formation pressure and directly with the thickness of the reservoir stratum. The rate of flow also increases with the well diameter in an, as yet, undetermined ratio that seems to vary with the magnitude of other variables. Laboratory studies have indicated that a 5-ft. well produces at a rate 1·5 times that of a 6-in. well. Theoretical analysis indicates that a 10-ft. well should attain a production 2·12 times that of a 6-in. well. The permeability of the reservoir rock depends upon the viscosity of the fluids, the pressure conditions operative, and upon the size, shape, and number of pores through which the fluids move. The number and character of the sand pores in turn depend upon the size, shape, and arrangement of the component sand grains. Pressure loss apparently varies inversely with the absolute viscosity of the oil and directly as the square of the mean effective diameter of the sand grains. The frictional resistance to flow is doubtless also influenced to some extent by the character of the mineral grain surfaces exposed to the fluids, and by the surface tension of the oil. Though theoretically there is, perhaps, no essential relationship between porosity and permeability, it is true that in so far as sands and sandstones are concerned, the more porous rocks are also the more permeable. Continuous or communicating pore space is here implied, not total porosity. In the Burbank field of Oklahoma, U.S.A., studies have shown [3, 1924] that wells producing from areas in which the productive sands had porosities of 30%, developed initial productions approximately 10 times those of other areas in which the porosity is only 18%.

Rate of Production and its Influence on Recovery Efficiency. From the standpoint of energy conservation, it is desirable to maintain a certain rate of production that is a function of sand permeability, well diameter, and formation pressure. A rate of production less than this may permit undue 'slippage' or 'by-passing' of free gas through the reservoir rock so that gas escapes to the well outlets without displacing its proper quota of oil: the efficiency of expulsion is reduced. On the other hand, as the pressure loss increases directly with the rate of flow through the reservoir rock, too rapid a rate of production will result in unnecessary energy consumption. Of course, economic factors, such as competitive conditions, the price of oil, and the interest cost of deferred production, must also be given consideration in determining the most desirable rate of production.

In the case of high-pressure flowing wells, a certain degree of restriction is often desirable, resulting in production of oil with a lower gas/oil ratio. Greater or lesser restriction in flow than the most efficient will lead to higher gas/oil ratios. While the rate of oil production is diminished somewhat by this practice, it is believed that the ultimate production is increased by the energy conservation effected. The rate of production of a flowing well may be restricted by applying back-pressure at the outlet, in the flow tubing, or at the gas separator. 'Chokes', often used for this purpose, are usually placed in the tubing near the well head. Back-pressures of many hundreds of pounds

are frequently used on high-pressure wells, directly reducing the pressure differential between the producing formation and the wall of the well, with corresponding readjustments in rate of flow, and in the pressure and energy gradients.

Much may be done in securing and maintaining proper back-pressures on producing formations by careful regulation of fluid levels in operating wells. A column of fluid maintained in the bottom of a well creates a certain static pressure which reduces by so much the differential pressure responsible for flow from the reservoir rock into the well. In flowing and gas-lift wells this is accomplished by flowing through an auxiliary column of tubing lowered in the well to the depth at which it is desired to maintain the fluid level. In wells that are mechanically pumped a fairly constant fluid level may be maintained by careful regulation of the rate of pumping, and it may be so arranged that the fluid level shall never fall below a certain point by suspending the pump so that the fluid intake is at this level.

We may increase the rate and efficiency of production of a well by enlarging it where it penetrates the oil-yielding strata. If well cavities several feet in diameter can be formed and sustained within the reservoir rock, the rate of production may be substantially increased, perhaps doubled. At the same time the gas/oil ratio will be reduced, indicating improved production efficiency. In hard reservoir rocks well cavities may be formed with the aid of explosives. In soft and semi-consolidated formations they may be formed by hydraulic means. Mechanical under-reamers may also be used for this purpose, but their range of operation is limited. In limestone reservoir rocks acid treatment will assist in enlarging the well cavity. Unconsolidated sands often tend to form well cavities naturally by flowing into the well with the oil. If reservoir rocks show a tendency to cave, the well cavity may be filled with gravel which preserves all the advantages of a well cavity, and yet supports the walls and prevents excessive sand incursion.

The Ultimate Recovery of Petroleum from its Reservoir Sands. The total production of petroleum available from an oil deposit by drainage through wells no doubt varies widely under different conditions presented in the field and is influenced by many different variables. Recovery will be greater with oils of low viscosity, in sands of high permeability and coarse grain size. Where production is dependent upon the expansive power of compressed natural gas, the ultimate production will increase directly with the initial field pressure. Within practical limits, the ultimate production will increase as the number of wells increases. Maintaining a certain spacing of wells, the recovery will be increased by drilling them of larger diameter. The rate of development will have an important influence on gross recovery.

The oil that still remains within the productive formation after the natural expulsive forces have been dissipated is retained within the pores of the reservoir rock by capillarity, and upon the mineral surfaces exposed to the oil by the reservoir rock. Most of the oil is left inert within the reservoir rock because of nature's inefficient use of gas energy with which the oil is originally charged. 'By-passing' of oil by gas forcing its way directly through partially drained spaces within the productive sand permits much of the gas to escape without moving its proper quota of oil. Pressure equilibrium between the formation and the well is thus reached, and movement of fluid by gas expansion ceases long before all the drainable oil has been expelled from the reservoir rock. Gas escapes from the reservoir rock more rapidly than the oil.

It is generally agreed that the percentage gas recovery will be materially greater than that of the oil, the only limiting factor preventing complete drainage of the gas being the minimum residual or equilibrium field pressure. The oil-drained spaces within the pores of the reservoir rock are left charged with gas at this residual pressure, and the undrained oil also remains saturated with dissolved gas at the equilibrium pressure.

Most of the estimates of percentage oil recovery offered by the literature, ranging from as little as 10 to 80% or more, seem to be based upon little more than the unsubstantiated opinion of the authors. When the expressed opinions are based on laboratory research, or careful analysis of field data, estimates seldom exceed 30%, and are generally less than 20%. The writer and his associates have conducted many different experiments to determine the ultimate recovery of oil, using several different types of apparatus and various methods of displacing the oil from the pore spaces of the reservoir sand. Percentage recoveries by gravity drainage, by gas expansion, and by water-flooding have been carefully determined for a variety of sand conditions and oil viscosities. Recoveries by gas expansion have usually ranged from 10 to 35%; by water-flooding from 15 to 75%; and by gravity drainage from 25 to 88%.

The ultimate recoveries indicated in the foregoing paragraph, secured in experimental tests, were obtained under ideal conditions with unconsolidated reservoir sands of unusually high permeability and uniformity of texture. In the field, where drainage is impeded by irregularity in sand permeability and by the greater distances over which flow occurs, the percentage yield must be much smaller. When the productive formation consists of a series of closely inter-stratified sands and shales, often displaying marked irregularity—a condition applying in many oilfields—a fair percentage recovery may be secured from the more permeable sand and sandstone beds, but very low recoveries are had from the less permeable shales and shaly sands. Because of the large percentage of the less permeable rocks in most oil-producing formations, it is believed that —considering the full thickness of the productive formation—the overall percentage recovery of oil must be, in most cases, materially lower than suggested by the results of laboratory experiments.

Actual recoveries in producing oilfields are reported to be as low as 15 or 20% by many authorities. Mining operations within the oil sands in the Pechelbronn oilfield in Alsace have indicated that the total recovery by producing to the lower limit of economic recovery through wells was only 16·7% of the total original oil content. Recovery estimates for the Bradford field of Pennsylvania by ordinary methods of flowing and pumping have been placed as low as 12½%. In diamond drilling between some of the wells in certain of the oilfields of Pennsylvania that had been producing for more than 60 years, part of the time under vacuum, the writer found that much of the oil-bearing formation cored still contained upwards of 90% of its original oil. Even the more permeable strata were found to be more than 60% saturated. In a formal statement before the U.S. Federal Oil Conservation Board, J. O. Lewis, one of the foremost authorities on secondary recovery methods, expressed the opinion that the average American oilfield yields only ⅕th of the original oil content by ordinary methods of pumping and flowing,

but that an additional ⅓th might be secured by pressure driving with gas or compressed air. In the opinion of Lewis, the maximum recovery by gas expulsion and gravity, aided by pressure restoration, is only 28%.

Those who believe that recoveries of the order of 50 to 80% of the oil present in the reservoir rock may be secured in ordinary field operations, generally assume that encroaching edge-water will displace much of the oil left behind by gas expansion and gravity drainage. In some cases, where cores have been taken of an oil sand behind an advancing edge-water front, the pores of the sand have been found to be practically free of residual oil. However, it is questionable whether, in such cases, the oil may not have been displaced from the sand during the process of cutting the core. Even though one might concede that the more permeable drainage channels are washed fairly free of oil by the advancing edge-water, there is good evidence for the belief that the water advances quite irregularly through different portions of the reservoir rock. The water passes more rapidly through the highly permeable channels, engulfing large bodies of 'tight' sand before the oil has been displaced from them. The results of flooding operations in the Bradford field of Pennsylvania indicate that less than 25% of the original oil content of the producing sands has been recovered by the combined processes of gas expulsion, gravity drainage, and water-flooding. Estimates of the ultimate recovery obtainable from California fields by present methods of exploitation, based on knowledge of reservoir sand thickness and porosity, production records, and decline of field pressure, seldom indicate percentage yields in excess of 15%.

Maintenance of Wells for Maximum Recovery Efficiency. For maximum efficiency in oil recovery, wells and well equipment must be free of detrital, waxy, and other accumulations which tend to restrict flow of oil and gas from the reservoir rock into the well and to the surface. Sand entering the well from the productive formation and shaly material caving from the walls of the well, unless brought to the surface with the oil, accumulate in the well and must be occasionally removed. Detrital material accumulated in the bottom of the well, or packed about the liner perforations or screens, will tend to restrict influx of oil from the reservoir rock. Paraffin wax, which may segregate from certain types of oil by evaporation of the lighter constituents of the oil, or by chilling of the oil as a result of rapid gas expansion, sometimes clogs the pores of the reservoir rock about the walls of the well, or the screens and perforations, or even the tubing through which the oil flows or is pumped to the surface. When waters carrying dissolved salts enter the well, inorganic precipitates may form and clog the reservoir rock and well equipment. Such precipitates may form by interaction between two different ground waters, or by supersaturation of dissolved salts resulting from evaporation of accumulated water in the well by gas bubbling through it.

Detrital material may be removed and screens and perforations cleaned by a thorough 'clean-out' operation, involving repeated bailing or swabbing, by washing, flooding, circulating, or hydraulicking with oil or water, or by blowing with compressed air. Inorganic precipitates may sometimes be removed by washing with fresh water, or if not soluble in water, by acid treatment. Waxy deposits may be removed with the aid of solvents such as oil, gasoline, or benzol, or by using heat-producing chemicals, steam, heated steel billets, or electric heaters. Explosives are often used in hard reservoir rocks to create heat and scale off clogged wall rocks prior to a thorough clean-out 'job'. The well cavity is thereby enlarged and the walls are left clean and free of clogging material. Powerful 'shots' of nitroglycerine or dynamite probably also create fractures which extend outwards in all directions from the well cavity, opening new drainage channels which increase production for a time and permit of greater ultimate recovery. In some fields wells are shot at more or less regular intervals to stimulate production.

Production Records an Important Aid in securing Maximum Recovery Efficiency. The progressive oil producer maintains systematic and detailed production records for each individual well. Such records are a useful guide in devising and maintaining a system of well control that will assure maximum recovery efficiency. They are also helpful in estimating future and ultimate recoveries. The oil and gas productions of every well are accurately gauged and recorded daily. Gas/oil ratios are computed therefrom. In the case of flowing or gas-lift wells, all pertinent information, such as casing-head pressure, tubing-head pressure, input gas pressure and volume, are continuously and automatically measured and recorded. The oil is regularly sampled, and its gravity and water and sediment content determined by appropriate tests. For convenient analysis and interpretation, much of this information is prepared in the form of continuous graphic charts.

In addition to these regularly recorded production data, other information is occasionally assembled in the study of special problems. Instruments are available for determining the pressure at any point within a well, or for gathering samples of fluid at any desired depth. 'Bottom-hole' pressures and samples of well fluid are of great assistance in analysing reservoir conditions and in so planning operations as to secure uniform drainage. 'Productivity factors', obtained for each well with the aid of bottom-hole pressure observations, enable the engineer to predict the rate of production of the well for any given pressure differential. Such information has been helpful in the application of production control in pro-rated fields, as described more fully by L. C. Snider in another article.

Systematic control of flowing wells, gas-lift wells, and mechanically pumped wells depends to an important extent upon the intelligent use of production records. The most efficient back-pressure to employ in the operation of a flowing well may be determined by careful observation of gas/oil ratios and productivity factors. Further discussion of flowing wells and their control will be found in another section under the authorship of C. J. May and E. S. Beale. Selection of the appropriate size and length of eduction tubes for flowing gas-lift wells will depend upon a careful analysis of oil and gas productions, gas-oil ratios, and upon surface and depth pressure conditions. Bottom-hole pressure observations are of great assistance in the adjustment of gas-input pressures and volumes in gas-lift wells as described more fully in another section of this volume by S. F. Shaw. Maximum efficiency in the operation of oil-well plunger pumps requires accurate knowledge of volumes of fluid to be handled, fluid levels in wells, length and timing of rod strokes, and other data as described more fully in the section on 'Oil-well Pumping' by H. H. Power.

The present section has been devoted primarily to a review of the conditions within the reservoir rock that control drainage efficiency. In so far as recovery methods have been discussed, these are concerned chiefly with

what might be called the primary systems of recovery in which oil is brought into the wells with the aid of natural forces latent within the fluids stored in the reservoir rock. Interest has been primarily in securing maximum efficiency in the use of these natural sources of energy. It has been shown, however, that the primary recovery methods are at best highly inefficient, and that a large part of the original oil content is left behind in the reservoir rock after all natural sources of energy have been exhausted. This residual oil may provide additional production by application of one or another of the so-called 'secondary' systems of recovery, in which artificially developed and applied energy is utilized to secure a second 'crop'. One of these secondary methods, involving repressuring and gas-driving, is described elsewhere in this volume by S. F. Shaw. Another effective recovery process involving displacement of residual oil from the reservoir rock by water-flooding operations is described in a separate section by G. H. Fancher. A still more efficient method of recovery, involving drainage of residual oil through mine openings instead of wells, also properly thought of as a secondary recovery method, in its present-day applications, is described by a pioneer exponent of this method, Paul de Chambrier.

A knowledge of reservoir conditions is even more important in the successful application of these secondary recovery methods than in primary exploitation. One of the principal difficulties with which the present-day petroleum production engineer must contend in the application of modern methods of oilfield exploitation in the older producing areas, arises from the lack of dependable subsurface information in the records preserved by the early oil producers. The modern operator is taking core samples of oil reservoir rocks in the course of drilling operations wherever possible. These cores are subjected to careful analytical tests designed to afford complete knowledge of the porosity, permeability, and stratigraphical disposition of individual sand layers and shale 'partings' throughout the full thickness of each producing zone. With such information at hand and a proper understanding of conditions within the reservoir rock which control the movement of fluids, a life-period programme of primary and secondary exploitation may be intelligently planned to secure the maximum economic ultimate recovery.

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THE POTENTIAL OIL YIELD OF RESERVOIR ROCKS

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FOR a long time it has been realized that the amount of oil normally produced from a reservoir rock is only a fraction of the amount originally contained in the rock. Estimates of percentage recovery, made in the past, have varied widely from 10 to 85%, but it is generally believed that the highest of these estimates have been decidedly optimistic. Of late years more attention has been paid to the question, particular interest having been shown in the determination of means by which the ultimate recovery might be increased. The research work carried out has been unable to provide any criteria by which the potential yield of a reservoir rock may be defined, and recoverable oil percentage remains a factor with very few characteristics of its own. Laboratory experimental work has many limitations, and it is important to remember that until checked by actual operations, the results can only be considered as indicative of what may happen.

In discussing potential yield it is essential to have a clear conception of the manner in which the undrained oil is retained. Since the greater part of the oil is produced from sand and sandstone reservoirs, the yield of such rocks has been studied somewhat to the exclusion of a consideration of the less important limestone, chalk, and igneous rock reservoirs.

In theory, the viscosity of the oil is not a factor determining the amount retained. High viscosity or internal friction retards the movement and rate of drainage of an oil, but relatively low pressures will overcome this effect, given sufficient time. In practice, however, viscosity does become a factor, for with a highly viscous oil production will decline to an uneconomic rate earlier than with a more mobile oil.

Grade of sand. Mean grain diameter (mm.)	*Percentage retentivity*
Greater than 2·54	6·7
2·54–1·56	9·6
1·56–1·04	13·1
1·04–0·63	12·1
0·63–0·41	14·6
0·41–0·25	15·5
0·25–0·16	14·5
0·16–0·10	15·3
0·10–0·085	28·6
0·085–0·064	32·7

FIG. 1. Percentage retention of liquids in sands of various sizes.

Theoretically, the percentage recovery is independent of the grain size of a sand reservoir, within certain limits, though the economic factor again becomes important with the reduced rate of drainage in the finer sands. This may be demonstrated by a simple series of tests utilizing flow-tubes packed with different sands of uniform grain size in the state of maximum compaction. The amount of oil required to saturate the sand and the amount capable of draining off are easily measured, and the table in Fig. 1 shows some typical results of such a series of tests. The size limits for constant drainage are 1·56 to 0·10 mm. mean grain diameter. Sands coarser than the upper limit retain liquid poorly, while with sands finer than the lower limit retention is increased. Heating the tubes will not increase the drainage, proving its independence of viscosity. The surface tension of the oil used was much less than that of water, yet within the size limits, for each sand the percentage of water retained was the same as that of oil. Apparently, then, in sands of these sizes percentage recovery is also independent of surface tension.

Smith [7, 1933] has made an interesting study of the final distribution of the retained liquid in a column of an ideal uniform soil, dividing it into three states. In the uppermost section the undrained liquid exists as a number of separate masses, each being in the form of an annulet round the contact point of two adjacent grains. Versluys named this the 'pendular' state. The liquid must remain thus to ensure a minimum of surface energy, though it is assumed that there is a wetting film, one or two molecules thick, over the grain surfaces. The film, however, constitutes only a very small portion of the retained liquid. Passing down the column, the annulets increase in size till Versluys' 'funicular' state is reached, where they coalesce, forming irregularly shaped masses. At the bottom of the column the third state is that of capillary retention. Referring again to Fig. 1, capillary retention only occurred in sands finer than 0·16 mm. mean grain diameter, though even in the 0·16–0·10 mm. sand the application of compressed air at 7 lb. per sq. in. reduced the saturation to the general average of about 14%. In sands of finer sizes the surface tension of the oil may be expected to affect the quantity of oil held by capillarity, most being retained with oils of high surface tension in the finer sands. Smith summarizes the results of some of King's experiments, and shows that with water in a sand of 0·12 mm. mean grain diameter the height of the capillarity zone is but 51 cm. Oil sands usually vary in size from about 0·09 to 0·21 mm. mean grain diameter and, as the surface tensions of oils are considerably less than that of water, the capillarity zone cannot be of much importance in a thick oil sand. In the same experiments, the 'funicular' zone was always about half as high as that of capillary retention. Hence we may conclude that in the average oil sand the largest portion of the sand would be drained to the 'pendular' state. Fig. 1 demonstrates that this type of retention is independent of the nature of the oil. It would seem, then, that the theoretical drainage is approximately the same for all oil sands, since the 'pendular' zone constitutes most of the drained sand.

Up to this point we have considered only an ideal drainage of 'dead' oil under the sole influence of gravity, and have reached the conclusion that at least 15% of the oil must be lost. Normal production methods are far less suited to perfect drainage. The oil is withdrawn from the reservoir rocks at a comparatively small number of points whither it has been propelled by the expansion of gas, the driving action of water, or a combination of both, and also by gravity action in the later life of the reservoir.

Of all experimental determinations of oil recovery due to the expansion of gas, probably the most noteworthy are those performed at the U.S. Bureau of Mines Petroleum Experiment Station [4, 1928]. In these experiments, oil saturated with gas at different pressures was produced

through a miniature well from sand packed in a flow-tube. Ultimate recoveries were highest with high saturation pressures and high rates of production, the difference in recovery between fast and slow production increasing with the saturation pressure. This difference was probably due to the fact that even the faster rates of production were too slow to give the optimum gas/oil ratio. The best recovery obtained was 40% with a saturation pressure of 800 lb. per sq. in., though it could probably have been increased by the introduction of some form of pump into the miniature well after natural flow had ceased. Reservoir pressures generally increase with depth so that deeper fields promise better recoveries. This is largely offset by the increased lifting costs reducing the amount of economic production after natural flow has failed. Expanding gas cannot move all the oil into wells, since slippage develops due to the greater mobility of the gas. 'Jamin' action has been suggested as a reason for low recoveries, but its occurrence in oil reservoirs is doubtful, and in any case its effect can only be small.

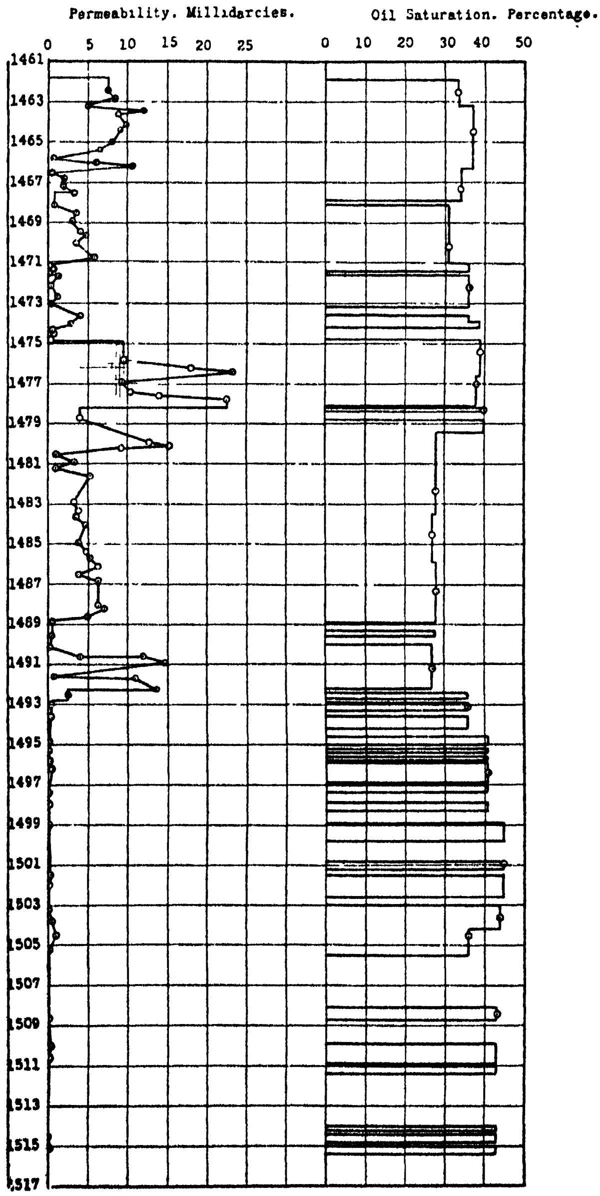

FIG. 2.

When an oil is depleted of its gas content, gravity action becomes a factor of increasing importance in the flow of oil into the wells. Theoretically, given sufficient time, a single well should be capable of draining a whole horizon. However, when the horizon is exhausted from the practical point of view, a drainage slope will exist round each well. Below the slope, the sand will be drained as far as is possible by the action of expanding gas, but gravity drainage from the upper parts of the reservoir will recharge it, and as no economic gravity drainage can take place from it, it will remain saturated. Each well can only drain an inverted cone whose apex is situated at the bottom of the well. Evidently well spacing is another factor determining the percentage recovery from a reservoir. Cutler's rule affords the best general definition of the part which it plays: 'For any given field, assuming equal well diameters, the oil recovery per acre will vary with the square root of the number of wells drilled per acre.'

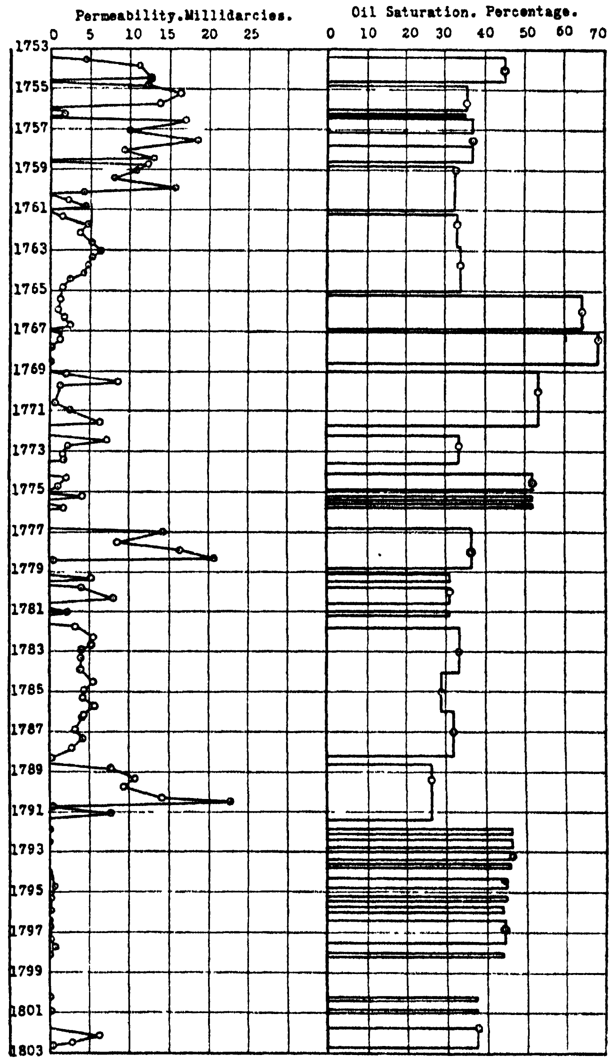

FIG. 3.

Better recovery may be expected from a uniform sand than from a streaky one in which the oil will drain more rapidly from the open streaks, thus providing a passage through which gas, escaping from the oil in the tighter parts, can move without moving its share of oil towards a well. This is illustrated by the log in Fig. 2, which is of a

well cored through the Bradford sand in Pennsylvania, after its exhaustion by ordinary production methods. Between 1,481 and 1,489 ft., where the permeability is fairly constant, the oil saturation is lower than that of the section from 1,473 to 1,479 ft., where, although higher on the average, the permeability is much more variable. The effect is somewhat masked by a second factor shown more clearly in Fig. 3 by the log of another well in the Bradford sand, where it is clear that at the end of economic exploitation, the retention of oil is lower in rocks of high permeability than in those of lower permeability.

The results of field activities lead us to conclude that without recourse to special methods the percentage recovery is considerably less than 40%, except under unusual conditions. The Powell field of East Texas showed an ultimate recovery of 43% from the Woodbine sand, which was regarded as exceptional [3, 1928]. The most widely adopted of special methods involve the injection or conservation of gas in 'pressure maintenance', 'repressuring', or 'gas-drive' schemes. From a theoretical consideration, pressure maintenance is considered to be the most satisfactory of these systems. In the study of repressuring conducted by the U.S. Bureau of Mines [4, 1928] it was found that 'the oil recoverable by repressuring depends among other things on the state of depletion of the sand being repressured. The percentage recovery of oil by repressuring tends to vary inversely with the degree of depletion that has been reached before repressuring is started.' It was also found that total gas/oil ratios increase sharply after 30% depletion, indicating by-passing. The results of the laboratory experiments suggested that approximately 52% recovery may be expected by normal production methods followed by repressuring. The results of practical exploitation are not quite so good, conditions not being so favourable. Three repressured areas, one in Kansas and two in Texas, indicate ultimate recoveries of 37%, 37%, and 40% as against indicated recoveries without repressuring of 25%, 28%, and 20% respectively. A field in Oklahoma, carefully exploited under a pressure maintenance scheme, shows a probable ultimate recovery of 37%.

Even at the end of the most efficient exploitation by the above methods, considerable quantities of oil remain in the sand, much of which can be recovered by secondary methods, notably by water-flooding and by mining. Water-flooding originated at Bradford, Pennsylvania, and has been so successful that its use is spreading into the Mid-Continent area of America. Fancher and Barnes [2, 1936] claim for water-flooding that it may produce oil impossible to recover by natural methods, particularly in sands lacking a natural water drive; that it will recover in a short time the dead oil normally left in stripper fields; and that the oil saturation of the sand, if sufficiently high, will be reduced to a fairly low figure, the process generally being able to remove 35 to 45% of the oil left in a sand of suitable physical properties. Production figures indicate that the average original saturation of the Bradford sand was 77%. Torrey [8, 1931] gives 60% as the average saturation at the start of flooding, and says that the average flood produces 40% of the oil present. Of the oil originally present, normal methods produce 22% and water-flooding a further 31%. A flooded area in northern Oklahoma had an original saturation of 43%. Normal methods produced 17·5%, and an established flood promises to bring the total recovery to 36·5% of the oil originally present. Torrey also states that the lowest limit of oil saturation in an average lens of the Bradford sand is never reduced to less than 15 to 20% by flooding. Furthermore, even in a reasonably uniform sand only 50% of it is watered out to this extent, though this should be improved by the modern method of delayed flooding. Also the whole of the area enclosed by a water-flood network is not flooded out. It has been shown that the efficiency of the usual five-spot pattern is only 72·3% [5, 1934]. It is interesting to note that cores of the flooded section of the Woodbine sand in East Texas have shown that only about 16% of the oil remained in the formation after flooding by encroaching edge-water [1, 1936]. Even and fairly rapid encroachment of edge-water is a big factor in obtaining good recoveries from sands without recourse to special and secondary methods. Much research work is being done in the search for a chemical compound to add to flood water in order to increase production by altering the interfacial tension relationships, but no suitable reagent has yet been found.

Of all methods of recovering oil from a sand reservoir, mining is probably the most efficient, though great difficulties are to be encountered. The only established oil-mines are those at Péchelbronn, France, and Wietze, Germany, both of which have been described by Rice [6, 1932]. The sands are generally drained by pits dug into them from underground galleries, or by drainage into the galleries themselves. Results at Péchelbronn indicate that wells are able to reduce the oil saturation of the sands (which are thought to have been almost fully saturated, originally) to 65 to 80%. Drainage in the mines reduces the saturation to an average of 35 to 40%, and in some extreme cases to as low as 17%. One of the sands at Wietze is mined, raised to the surface, and washed with hot water and soda, by which means 90% of the oil contained in the sand as mined is recovered. This would seem to be the only method of reducing the saturation to the order of 3 or 4%.

Chalk and limestone reservoirs present an entirely different set of conditions, the oil being contained in small cracks and fissures, or occasionally in quite large cavities. In the latter case, very high percentage recoveries may be expected.

The cracks and fissures are usually wider than the passages between the grains of a sandy reservoir, and should be drained more readily. Laboratory experiments show that the adsorption of oil by limestone is high, and by chalk even higher, but most of these experiments have been performed on dry material. Any water which may be present will reduce the adsorption effect to an almost negligible figure. Lastly, in chalk and limestone reservoirs the pores do not intercommunicate as much as in sandstones, and this is probably the most important factor in determining the extent to which the reservoir may be drained. In limestone producing areas of Kentucky it has been found that new wells drilled between 17-year old producers now making less than a barrel per day, frequently have initial productions approximating to those of the old wells when first drilled in [9, 1936]. Percentage recovery is difficult to calculate on account of the doubtful original content of the reservoir. However, it is stated that in the Kentucky area the limestone was depleted by 12 to 25% before repressuring was commenced. Percentage recovery from igneous rock reservoirs is difficult to assess for the same reasons. In such rocks the adsorption effect is less than in chalk and limestone, but again recovery is determined by the size of the oil-containing fissures, and the extent to which they intercommunicate.

In the future it is probable that mining and water-flooding will be adopted more widely in the shallower fields. Such methods will involve great difficulties in deeper

fields, and would be uneconomic at present prices, so that ultimate recovery must be increased by repressuring, or by pressure maintenance in new fields. There is little doubt that the extensive research programmes in progress and yet to be instituted will greatly improve and increase the applicability of all such production methods, which must inevitably lead to the attainment of larger recoveries in the future than have been obtained in the past.

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THE SCIENTIFIC STUDY OF THE FLOW OF OIL IN WELLS

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Introduction

CRUDE oil in the underground reservoir of an oilfield is nearly always found to be under pressure, and this may be either greater or less than would be necessary to balance the hydrostatic pressure of a column of 'solid' oil up to the surface of the ground. These two cases may be compared with an 'artesian' and an ordinary water-well respectively.

In the case of a water-well this criterion is of fundamental importance, since it determines whether a well will flow or has to be pumped, but in the case of an oil-well the pressure of gas in solution, or produced along with the oil, so modifies the conditions of flow by lightening the column of oil that the exact value of the 'hydrostatic pressure', as it is called, is only one of the important factors affecting the flow.

The problem is very complicated as compared with the case of the water-well, and anything like an exact solution must depend on a considerable amount of reasonably accurate data for each individual case, some of which is rather difficult to obtain in practice; but the value of a knowledge of whether any well will flow, and if so at what rate, at what stage in its life will a well go to pumping, what improvement in the flow would be effected by changing the size of the flow string, and so on, is so great that a considerable amount of effort in obtaining the necessary data is usually well worth while.

Given the required basic data, the calculation of flow is not by any means exact except in certain circumstances, such as with very large wells flowing in large-diameter flow strings at neither a very high nor very low velocity, since the sources of energy loss, such as friction and slippage of gas through the oil, are usually of great importance. These are difficult to evaluate precisely owing, among other things, to doubt about the condition of the gas and oil mixture on which these losses clearly depend. For instance, the losses will differ greatly according to whether the mixture is in the form of a foam or of a mist.

In the following article an attempt is made to present the fundamental factors which govern the flow of oil and gas in a well and to give the best methods of calculation from them in such a way that, where there is a similar problem in another branch of engineering we may profit by the comparison, and where there are obvious gaps in our knowledge, these can be most easily filled up by scientific observation.

General Mechanism of Flow in Wells

When all the major factors which affect the flow in an oil-well have been taken into account the problem becomes rather complicated owing to the interdependence of one factor on another. It is therefore most important to get a clear mental picture of the situation, so that great care should be taken to choose the best general way of considering the problem.

There are three distinct ways of regarding the mechanism of flow of oil in a well depending on whether the flow is regarded as due to:

(1) a pressure difference acting on a column of fluid of varying density;
(2) the energy of expansion of a mixture of oil and gas, usually exhibited on a P-V diagram, as for a steam-engine;
(3) the change in heat content and increase in entropy of the mixture, exhibited on a θ-ϕ or H-ϕ diagram, as is customary with heat engines of all kinds.

Depending upon which of these points of view is chosen, so will the treatment of the various resistances to flow differ. Each of these aspects has advantages over the others in certain respects, and a brief review of each in turn will facilitate the choice of the most suitable method for any particular purpose.

Nomenclature

The following nomenclature is used throughout the present article. For the sake of consistency it has been necessary to make various alterations from the symbols selected by authors who have published work on the subject, and this fact should be borne in mind when referring to original papers.

		F.P.S. °F. units
P	Pressure	lb. per sq. ft.
P'	Pressure	lb. per sq. in.
V	Specific volume (of flowing mixture oil pressure P)	cu. ft. per lb.
$\rho = 1/V$	Density (of flowing mixture oil pressure P)	lb. per cu. ft.
ρ_{av}	Mean density over column of oil-gas mixture	lb. per cu. ft.
ρ_L	Density of liquid	lb. per cu. ft.
D	Flow-string diameter	ft.
D'	Flow-string diameter	in.
A	Cross-sectional area	sq. ft.
w	Mass flow (total weight of fluid passing casing in unit time)	lb. per sec.
q_o	Volume of oil passing given section of casing in unit time	cu. ft. per sec.
q_g	Volume of free gas passing given section of casing in unit time	cu. ft. per sec.
v	Linear velocity	ft. per sec.
g	Acceleration due to gravity	32·2 ft. per sec.^{2}
b	Velocity of slip	ft. per sec.
h	Vertical height (in well)	ft.
η	Absolute viscosity	Poises
$\nu = \eta/\rho$	Kinematic viscosity	Stokes
$k = R/\rho v^2$	Friction factor	..
γ	Surface tension of liquid	dynes per cm.
T	Temperature	° Rankine
θ	Temperature	° F.
ϕ	Entropy	B.Th.U. per lb. per ° F.
H	Heat content	B.Th.U. per lb.

1. Pressure Difference Method.

In this case the flowing well is regarded as a column of fluid whose density can be specified at each point over its vertical height. This column is acted on by an upward pressure at the bottom and by a smaller downward pressure at the top. The difference between these pressures is regarded as the sole cause of flow.

The primary force opposing flow upwards is clearly the

weight of the column of fluid acting downwards. As in a hydrostatic problem, this is equivalent to a pressure difference equal to $h \times \rho_{av}$.

Any effects due to slippage of gas through the oil must be taken into account in arriving at the density of the fluid at each point, and hence the average density, ρ_{av}.

If the difference between the bottom and top pressures exceeds that due to the weight of the column, then flow will take place at such a rate that the various resistances to flow are just equal to this excess.

These resistances to flow, just as in any pipe-flow problem, are due to friction against the walls and to increase in velocity head.

These could be evaluated as in pipe flow (see article on 'Flow in Pipelines') by assigning suitable values to the friction factor k and the velocity-head factor C, and the general equation in its elementary form becomes:

$$(P_1-P_2)-h\rho_{av} = \int\limits_0^h \frac{4k\rho v^2}{gD}\,dh+\frac{C\rho_2(V_2^2-V_1^2)}{2g}.$$

It should be noted that the top and bottom pressures in this equation, P_2 and P_1, refer to the pressures in the well itself, and the pressure drop at the foot of the well and at the flow-head valve must be taken into account in arriving at these pressures. Alternatively, if the overall pressures are used in the equation, additional empirical friction terms must be added which will be some function of the throughput or the density and velocity or viscosity of the fluid at each of these places.

A little consideration will show that the integral form for the friction term is necessary, since the total effect of friction is the sum of all such resistances over the height of the well, and the density ρ, the velocity v, and possibly also the friction factor k, are changing as we go up.

The velocity-head factor should, strictly speaking, be corrected for slippage to allow for the difference in the kinetic energy due to the different velocities of the oil and the gas, but this would be a very considerable added complication, and since the effect is small in most cases it is best omitted.

It will be noticed that in this method of presentation the energy of expansion of the oil-gas mixture does not appear directly at all, but it is actually involved in the calculation of the average density of the column. It would appear also from this treatment that the source of energy lies in the difference between the static pressures at the top and bottom of the column, but it will be seen that this is not so from the energy considerations in the next section.

One of the chief objections to this method is the difficulty of arriving at the density at each point in the column. The average density must clearly be obtained by integrating the curve connecting density with height in the well. Now the density depends primarily on the pressure; and the pressure at any point depends not only upon the height and the density at all other points in the column, but in addition on all the various resistances to flow.

This method in its most developed form has been used by Moore and Wilde [12, 1931; 11, 1933] for oil-wells, and is the one most generally used in calculating short air or gas lifts. In any case it is the simplest for arriving at a calculated value for slippage losses as explained below.

2. Energy of Expansion Method.

Here attention is focused on the sources of mechanical energy of the system and the ways in which this energy is consumed. Considering first the top and bottom pressures as above, energy equal to P_1V_1 per unit mass is put into the system at the bottom and energy equal to P_2V_2 is taken out at the top, where P_1V_1 and P_2V_2 are the pressures and volumes of unit mass of the fluid entering the bottom and leaving the top respectively.

The net input of energy from this cause is therefore $P_1V_1-P_2V_2$. In the case of an incompressible liquid this is considerable, since P_1 is usually much greater than P_2 and the volume is constant. In fact this is the only source of energy causing flow of such a fluid. In the case of a perfect gas at a constant temperature it will be remembered that PV is constant, so that the net energy from this source would be zero. Now in the case of an oil and gas mixture the volume is not constant, and P_2V_2 may be either greater or less than P_1V_1, depending on the circumstances, and in many practical examples the difference is found to be very small or actually negative. This point is stressed here because, although it has frequently been mentioned by Versluys and others, some confusion still occasionally arises from overlooking it.

Clearly, then, we must look elsewhere for the chief source of energy in a flowing well, and it is, of course, found to be the energy of expansion of the mixture, which is expressed in the usual mathematical form, $\int_{V_2}^{V_1} P\,dV$. The combined energy input from both sources is therefore equal to

$$(P_1V_1-P_2V_2)+\int_{V_2}^{V_1} P\,dV.$$

A considerable simplification is achieved if these two sources of energy are combined into a single expression, and this is best illustrated with the help of the familiar 'Rankine Cycle' used in the analysis of steam-engine per-

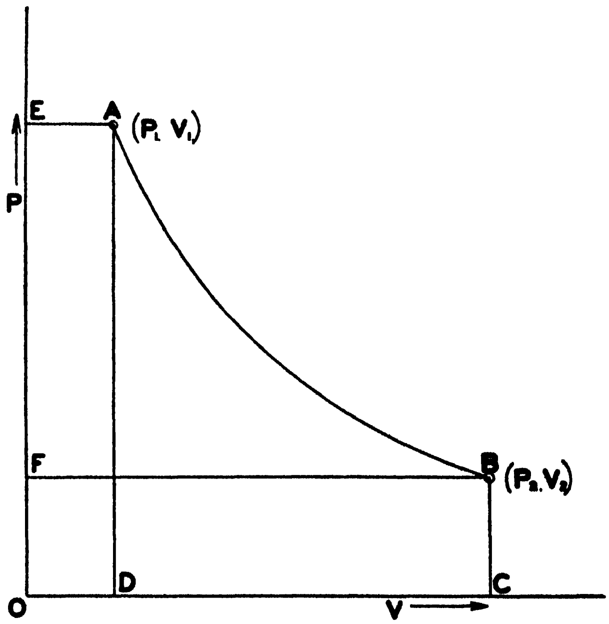

FIG. 1.

formance. Fig. 1 shows the expansion line on the ordinary pressure/volume diagram of a fluid expanding from a pressure P_1 and volume V_1 represented by the point A, to a pressure P_2 and volume V_2 (point B). In this diagram the energy of expansion $\int P\,dV$ is represented by the area $ABCD$.

Now the energy $P_1 V_1$ is similarly represented by the area *ADOE* and $P_2 V_2$ by *BCOF*; therefore $\int P\,dV + P_1 V_1$ is equal to the area *ABCOE*, and subtracting $P_2 V_2$ we are left with the area *ABFE*, which represents the combined energy input and is expressed mathematically by $\int_{P_2}^{P_1} V\,dP$. Therefore we have:

$$\text{Net energy input} = \int_{P_2}^{P_1} V\,dP = (P_1 V_1 - V_2 P_2) + \int_{V_2}^{V_1} P\,dV.$$

Turning now to the various ways in which this energy is consumed, we have:

(1) *Lifting the Oil against the Force of Gravity.* This is the primary consumption of energy, and a well flowing at 100% efficiency is one in which the whole of the available energy is applied to lifting the oil and gas, or giving it potential energy equal to *gh* per unit mass.

This efficiency refers, of course, to the flow in the well itself and excludes the losses which occur at the foot of the well and at the flow-head valve.

(2) *Friction at Foot of Well.* This is best treated as a loss external to the well by estimating what the reduction of pressure in the well itself will be from this cause at any particular rate of flow, and using this reduced pressure in the flow calculation. This subject is dealt with more fully below.

(3) *Slippage.* Owing to the difference in density, gas tends to slip past the oil, and when this occurs energy is consumed in friction in the body of the mixture and is converted there into heat. The calculation of this loss of energy depends on the relative velocity of the gas and the oil, and is given in detail later.

(4) *Friction against the Walls.* The friction loss is calculated for the appropriate value of the ordinary friction factor. This energy also is converted into heat in the well.

(5) *Kinetic Energy Loss.* A certain amount of kinetic energy is carried away from the system owing to the increase in velocity of the mixture between entering and leaving the well. This term should theoretically depend to a certain extent on the velocity of slip, but the correction is so small it need not be considered in practice.

In order to calculate the value of the available energy, $\int V\,dP$, it is necessary to know the pressure-volume relations for the fluid actually entering the well at the temperature of flow. Now the temperature at any point in the well depends on several factors: the temperature at which the fluid enters the well; the lowering of the temperature due to the gas coming from solution and expanding while doing work; the rise of temperature due to the heat generated by slippage and friction as noted above; and any change due to heat flow into or out of the well through the walls.

These effects are interdependent to some extent, and an exact calculation of them would be very difficult, if not impossible. However, it is an easy matter to measure the temperature of a well while flowing, and if this is done all these effects can be simply considered as contributing to the final observed temperatures.

Furthermore, in certain cases, more particularly where the total change of temperature is fairly small, a considerable simplification can be made without serious error, as has been pointed out by Versluys [17, 1930], by taking the available energy from the curve representing the mean temperature of flow instead of for a curve specially constructed for the temperature at each point in the well.

With the exception of the interaction of the various effects via the temperature, which is conveniently dealt with as described, the only interdependence of any importance is that of slippage and friction, for the reason that friction modifies the pressure at each point in the well, and the pressure determines the ratio of gas to liquid, and this in turn determines the slippage. However, this is not a serious difficulty and is dealt with later.

This 'Energy of Expansion Method' was first applied in detail to flow in oil-wells by Versluys [17, 1930], and it has been discussed at some length as it has many points of advantage over the 'Pressure Difference Method', in that it probably presents a truer picture of the mechanism of flow.

3. Thermal Energy Method.

By this method the subject is treated in the well-known alternative manner used for heat engines in general, namely, by calculating the total work done by the oil-gas mixture during flow from the change in heat content and entropy of the system, and equating this to the sum of the energy consumed due to all causes, including those which are purely mechanical, by means of the mechanical equivalent of heat.

Since we are dealing with exactly the same individual energies as in the last method, the two treatments are exactly equivalent.

In order to arrive at this available energy it is first necessary to determine experimentally an entropy and heat content diagram for the reservoir crude which is most conveniently exhibited in the form of a diagram in which entropy is plotted against temperature for various pressures, with lines of constant heat content superimposed. Lines of constant specific volume on the chart are also useful. Lacey has found it preferable in practice to plot the function $\phi - 0{\cdot}0008\ (t-60)$, where t is the temperature in ° F. instead of the simple entropy, ϕ, in order to obtain a more open diagram. A chart of this type is given on Fig. 2.

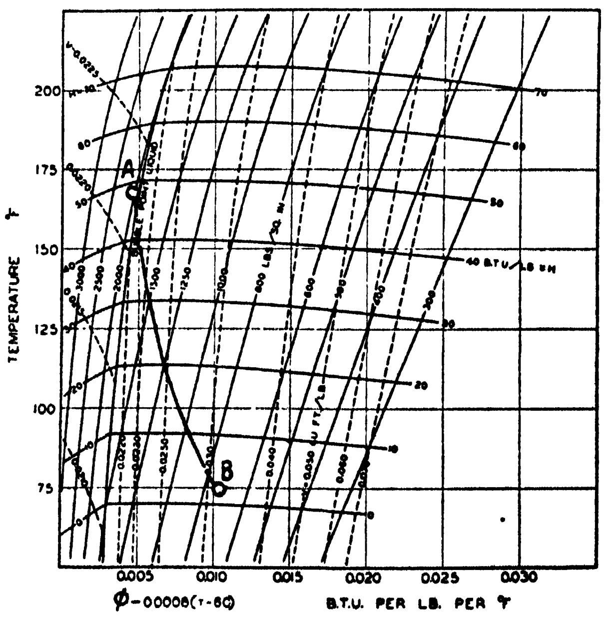

FIG. 2. Temperature-entropy diagram.

To apply this chart to a particular well the pressure-temperature curve for the fluid in the well must be determined under actual flowing conditions, and from this data one obtains:

(i) The difference in the heat content of the fluid between

the two points representing the pressure and temperature at the top and bottom of the well respectively.

(ii) The entropy-temperature curve representing the thermodynamic path in the well. This curve is then integrated graphically to give $\int \phi\, dT$, which is the heat which would be absorbed from the walls of the well during frictionless flow, i.e. in a reversible process.

The heat content or total heat is defined as the sum of the internal energy, E, and the product PV. The difference in this quantity between the bottom and top of the well therefore represents the total *loss* of energy (due to useful work and transfer of heat to the walls). The function $\int \phi\, dT$ is the heat *absorbed* from the walls plus the friction losses.

The sum of these two quantities is the total amount of heat converted into work, and this must be equal to the total energy absorbed in lifting the mixture against gravity, friction, slippage, and kinetic energy as previously described, less any mechanical energy put into the system.

This type of chart is particularly useful when an analysis of the changes in temperature in a flowing well is being made, since temperature changes form an integral part of the process of calculation. With this exception, this 'Thermal Energy Method' is simply another way of presenting the same data as given by the pressure-volume-temperature charts. The practical use of such thermal charts is best illustrated by means of a hypothetical example:

Fig. 2 represents actual experimental data obtained by Lacey on a crude oil together with its normal complement of gas. The curve AB represents the observed pressure-temperature relationship during flow at a rate of 40·6 bbl. per day from a depth of 5,122 ft. to the surface.

Now the difference in heat content between A and B is 46·6 B.Th.U. per lb., so that this amount of heat is *lost from* the oil during flow. Of this, 6·59 B.Th.U. per lb. ($\equiv$ 5,122 ft.-lb. per lb.) is converted into useful work, i.e. lifting against gravity, leaving 40·0 B.Th.U. per lb. If now we integrate the area under the curve AB down to the absolute zero (by planimeter or by counting squares), we obtain the heat which would be absorbed by the oil in a 'reversible' (frictionless) process. This proves to be $-39{\cdot}7$ B.Th.U. per lb. Therefore with no waste of energy (as friction, &c.) the oil would give up 39·7 B.Th.U. per lb. to the surroundings. Actually, after allowing for useful work done, it loses 40·0. The friction loss is therefore $40{\cdot}0-39{\cdot}7 = 0{\cdot}3$ B.Th.U. per lb. ($\equiv$ 1,240 ft.-lb. per lb.).

It may be observed that the path DE does not need to be determined with very great accuracy, since wide variations from the sort of line shown on the diagram are improbable and small variations will not seriously affect the result.

Lacey [5, 1934; 6, 1935] has recently published some data on the condensed liquid region of a degassed crude and also on a reservoir crude with its dissolved gas [5*a*, 1935] using this method of presentation, but the method has not been elaborated in the literature.

The example given above is taken from the last paper by Sage and Lacey. A second example is given by them for flow at 1,009 bbl. per day which brings out the interesting point that, although at the higher rate of flow the friction loss is greater and the flowing pressure lower, the actual heat content of the surface oil in this case is greater due to the smaller heat loss and higher surface temperature.

Thermal charts of this kind must be constructed from very accurate thermal data if they are to yield results for the energy of expansion of the same accuracy as is obtained directly from the determination of the P-V-T characteristics. In view of the present shortage of data and experience in the use of the method it is not here considered in further detail.

Flow at the Foot of a Well

The drop in pressure, with its consequent energy loss, as the oil (and gas, if any) enters the well from the oil-bearing formation is in rather a different category from the other losses, as it bears directly in many cases on the influence that production from a given well has on the formation itself. This subject is therefore treated somewhat fully, though the discussion is confined to a consideration of the flow near the foot of the well as distinct from flow in the reservoir as a whole.

The same quantity of oil which leaves the well-head in a given time must obviously enter the foot of the well from the formation during the same period except during surging or unsteady flow, and clearly, therefore, the resistance to flow offered by the pores or fissures in the oil-bearing formation which feed the well has a direct effect on the pressure in the well itself. This resistance will not only modify the flow in the well, but it may also be the cause of quite different effects due to changing the conditions in the formation in the vicinity.

The channels by which the oil (and gas) reaches the bore of the well are of two general types—pores and fissures.

In a sandfield the well may be drilled into a fairly uniformly porous stratum, and the oil may enter the well over a large proportion of the surface area of the open hole.

On the other hand, in some types of limestone field, for example, in the Iranian field at Masjid-i-Sulaiman, the oil probably enters the well almost exclusively by fairly well-defined fissures, which are themselves fed from the pores of the oil-bearing formation.

These fissures may extend for large distances and present a very great surface area. The well is thus enabled to drain a formation which has very low permeability although having a quite substantial porosity, there being no essential connexion between these two properties (Fancher and Lewis [2, 1933]; Wyckoff, Botset, Muskat, and Reed [20, 1934]).

In the case of a uniformly porous sandfield the resistance to flow at the foot of the well is determined by the permeability of the oil sand and the length and diameter of the open hole in the producing formation, presuming that the resistance of any perforations at the foot of the flow string is negligible.

Except in the case of very coarse sands of high permeability at very high-pressure gradients the flow in the pores is probably stream-line [2, 1933], and therefore the effective viscosity of the fluid under the conditions existing at the foot will be the controlling property, apart from the effect of velocity head which in these cases should be very small.

If there were no gas present, most of the resistance to flow would occur close to the foot of the well, but the presence of gas bubbles very greatly modifies the flow in a porous mass, particularly under small pressure-gradients, and will, among its many effects, cause the drop in pressure to extend to a very much greater distance from the foot of the well and also makes the conception of a true 'rock-pressure' very much more difficult to realize; since, when

gas liberation in the pores has got beyond a certain stage, the rock-pressure may not entirely recover its 'proper' value at the foot of the well when a well is closed in.

In the case of a well in a limestone field which is fed essentially by fissures, this resistance is determined almost entirely by the shape and size of the fissures which the well has encountered. Even in a fairly large well producing, say, 5,000 barrels per day, the fissures may be quite small of the order of 1 mm. thick or less. In such a case the flow may be turbulent in the fissure at high rates of flow, and there may be a very large effect attributable to velocity-head at the mouth of the fissure, which may, in fact, be the major part of the whole resistance to flow. At low rates the flow may be stream-line and the effect of velocity head negligible.

It should be clear, therefore, that, although the drop in pressure due to this resistance at the foot of the well depends on the rate of production, it is not necessarily directly proportional to it and may, in fact, be more nearly proportional to its square. This drop in pressure at the foot of the well is often referred to as the Bottom-Hole Differential Pressure, abbreviated to B.H.D.P., and if its limitations are clearly realized, this is a useful conception.

This B.H.D.P. represents a drop in pressure below the rock-pressure which would have existed at the same point in the formation and at the same time if no production were being drawn from the well.

In some fields with free connexion within the formation, this (true) rock-pressure may be a very definite thing which can be measured directly a well is shut in and be correlated exactly with the rock-pressure in neighbouring wells at the same level. In other cases, however, this cannot be done satisfactorily, owing to gas-locking of a porous formation, slowness in reaching any kind of pressure equilibrium after shutting in, &c.

In such cases the use of the idea of a B.H.D.P. is of little value and the facts are best represented by curves giving the actual bottom-hole pressure at different rates of production and times.

Apart from the direct effect on the pressure in the well near the foot, the B.H.D.P. may affect the flow in another way which may be even more important.

There are two cases having roughly the same overall effect, but otherwise differing completely.

(1) If there is a surface of separation between the oil and the gas in the oil-bearing formation, and if the surface is not far above the point at which the well draws from this formation, the existence of a large B.H.D.P. will tend to 'cone down' gas, thereby increasing the ratio of gas to oil being produced by the well. Or conversely, it will tend to 'cone up' oil if the surface of separation is below the foot of the well, and if there is an oil-water contact near the foot of the well, water may similarly be 'coned up' and produced with the oil, or the proportion of water to oil seriously increased.

(2) In the case of a formation of low but uniform permeability the existence of a large B.H.D.P. reduces the pressure on the oil in the region round the foot of the well which may therefore bring gas out of solution, and the gas liberated in this way may reach the well, while the oil from which it came may not. This would again result in an increase in the ratio of gas to oil in the well.

However, except for a possible distinction between this 'free gas' entering the well from the formation and gas liberated from solution in the well itself, all the information necessary to allow for this effect on the flow in the well is given by the measurement of the gas/oil ratio at the surface, regardless of the exact mechanism by which it is produced.

Details of the Expansion Energy Method

For the reasons given above the method of calculation based on the energy of expansion appears on the whole to be the most suitable for detailed exposition in the present article. In particular it is the one which is most likely to yield rapid developments in those parts of the subject which are still somewhat obscure. The most recent detailed account of the theory is that of May and Laird [10, 1934], which is taken as the basis of the present treatment, partly in order to provide a consistent foundation throughout, and partly in order that references may be made to an easily accessible paper for certain mathematical details which it is not proposed to reproduce. For purposes of easy comparison the work of certain authors is presented in a slightly modified form which is, however, exactly equivalent to the original.

It may here be observed that it is common practice in the study of hydraulics to express results in terms of 'head' of fluid—'so many feet head' being a pressure equivalent to a column of the fluid in question of that particular height. When the fluid is varying in composition and density, this terminology is liable to be confusing. By working in terms of energy, one common unit can be employed irrespective of the nature of the fluid or of any variations in its properties. The unit is one foot-pound per pound of fluid. Both in dimensions and numerical magnitude, energies expressed in these units are exactly equal to the corresponding 'heads', but the terminology is less likely to lead to mental confusion.

Available Energy.

It has been shown above that, given a compressible fluid, for a small drop in pressure dP and increase in specific volume dV the work done by expansion is PdV and by the static head $PV = (P+dP)(V+dV) = -PdV-VdP$. The total is therefore $PdV-PdV-VdP = -VdP$ or over a finite range of pressures $-\int_{P_1}^{P_2} V\,dP = \int_{P_2}^{P_1} V\,dP$ ft.-lb. per lb. of total fluid, the pressure being in lb. per sq. ft., P_1 the higher and P_2 the lower pressure, and V being the specific volume of the oil-gas mixture in cu. ft. per lb. Expressing the pressure in the more usual units of lb. per sq. in., the available energy becomes

$$144\int_{P_2''}^{P_1''} V\,dP''.$$

Energy Usefully Employed.

Within the well the only useful work done is that required for lifting the oil against gravity. Over a height dh this obviously amounts to:

$$dh \text{ ft.-lb. per lb. of total fluid.}$$

It may here be observed that ordinary production measurements are made in terms of gallons or barrels of flow tank oil, but that since work has to be done in lifting the associated gas, this figure must be converted to pounds and have added to it the weight of gas and of any water simultaneously produced for the purposes of the present calculation.

Energy Losses.

Still considering flow only within the well itself, there are three ways in which energy is normally dissipated—

velocity head, friction, and slippage. These have been examined theoretically by a number of authors—in particular by Versluys [17, 1930], May and Laird [10, 1934], Moore and Wilde [12, 1931], and Moore and Schilthuis [11, 1933]. It is not proposed to detail the methods employed since, in the main, they follow normal hydrodynamic practice. No difficulty arises until we attempt to assign numerical values to the various physical constants of the heterogeneous mixture of varying composition flowing in the well. Consider the various losses in turn.

(1) *Increase in Velocity Head.* As the specific volume of the fluid increases, the velocity, and therefore the kinetic energy, also increases. (In practical cases the energy losses due to this cause are usually negligibly small.) If w is the number of lb. of total fluid (oil and gas) flowing per second through casing of area A sq. ft., the velocity is evidently Vw/A and the kinetic energy $V^2w^2/2gA^2$. The increase in velocity head for a small drop in pressure is therefore

$$\frac{Vw^2}{gA^2}dV \text{ ft.-lb. per lb. total fluid,}$$

where dV is the corresponding small increase in specific volume.

(2) *Friction.* From ordinary hydrodynamic theory, remembering that Vw/A = velocity, the work done against friction in a small distance dh is given by the equation

$$\frac{4kV^2w^2}{gA^2}\frac{dh}{D} \quad \left(\text{i.e. } \frac{4kv^2}{gD}dh\right),$$

where D is the casing diameter in feet, and k is a friction factor equal to a function of the Reynolds number $vD\rho/\eta$ and normally derived from the ordinary Reynolds-Stanton curves. In the case of a heterogeneous mixture of oil and gas it is not easy on theoretical grounds to ascribe a value to the effective kinematic viscosity, and much of the experimental work that has been carried out has been aimed at evaluating this friction factor (see below).

(3) *Slippage.* Owing to the difference in density, separated gas tends to rise in the well faster than oil, and energy is thereby dissipated in the form of heat. Various methods have been proposed for calculating this loss, representative of which may be taken that of May and Laird [10, 1934]. In the first place it appears that in their experiments slippage was only of appreciable magnitude at such low velocities that friction was negligible. Under such conditions the pressure difference (lb. per sq. ft.) between two points in a vertical column of fluid of uniform cross-sectional area is evidently equal to the weight (lb.) of material per unit area (sq. ft.) between the two points in question. Due to the difference in velocity between gas and oil, a distinction must be drawn between the actual and the effective gas/oil ratios at any point in the well. At any cross-section the actual gas/oil ratio is the ratio of gas to oil passing through at any given time, while the quantity effective in determining the lift is the ratio actually present at the section at any instant. If we know the velocity of slip, b, between the two phases, it is easily possible to calculate the effective gas/oil ratio, and hence the effective density of the mixture, at any point in the well. From what has been said above, the height to which oil will rise for a given small pressure drop dP can easily be calculated, and this subtracted from the available energy gives the slippage loss according to May and Laird as

$$\frac{144(V-1/\rho_L)}{V(w/Ab)+1}dP'' \text{ ft.-lb. per lb.}$$

It remains to determine the quantity b experimentally (see below).

The General Equation of Flow

The possible case may arise in which both friction and slippage are simultaneously of appreciable magnitude, as in the 'mist' type of flow postulated by Versluys. Moore and Wilde, therefore, correctly add the friction head to the hydrostatic head and equate to the pressure difference in arriving at a formula for the slippage loss. Using the present method of calculation, it is necessary in order to obtain an equivalent result to add the various energy losses to the useful work done and equate to the available energy to obtain the general equation of flow:

$$144VdP'' = dh + \frac{Vw^2dV}{gA^2} + \frac{144(V-1/\rho_L)}{V(w/Ab)+1}dP'' + \frac{4kV^2w^2dh}{gDA^2}.$$

This expression is given by May and Laird [10, 1934] and is formally similar to that of Versluys [17, 1930] and of Moore and Wilde [12, 1931], the most important difference being in the fact that the quantity V is left for experimental determination and is not calculated from the simple gas laws. In addition, experimental measurement of the quantities ρ_L, b, and k is necessary before the equation can be completely solved. If this data can be obtained, integration of the equation yields a straightforward relationship between pressure drop, depth, and casing diameter of well, and weight throughput.

The Pressure-Volume Curve

Numerical computation from the above general formula and the evaluation of the various energy losses requires a knowledge of the volume occupied by 1 lb. of reservoir crude with its associated gas at various pressures. Versluys proposed to calculate this on the assumption of Henry's law and Boyle's law. This method is of some use as a rough approximation and may prove of value in extrapolation

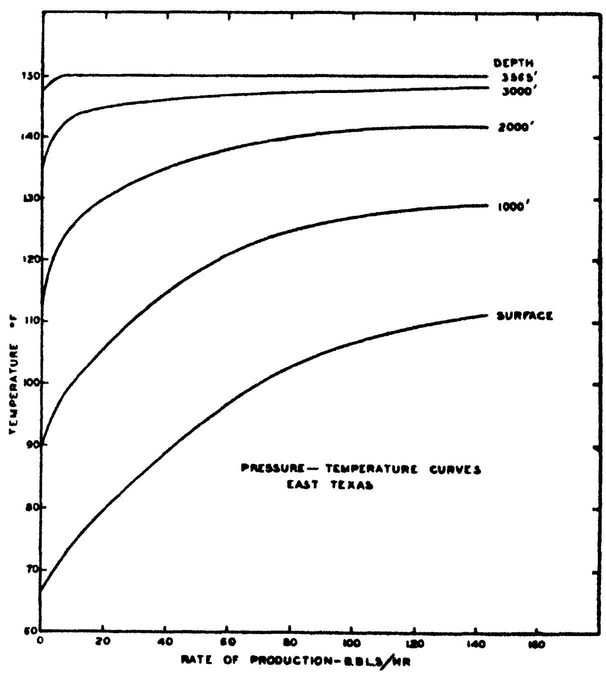

FIG. 3.

over narrow ranges and at high pressures when the gas evolved from solution is almost pure methane. It is, however, far from being accurate in the general case. The

deviation from Boyle's law of methane, for example, is some 10% at 600 lb. per sq. in., and when the composition of the gas evolved from solution is changing, as it does, over wide ranges of pressures, calculation of the *P-V* curves can only be done by taking the solubility factor for each gas individually. Both Lindsly and May and Laird therefore suggest eliminating these sources of error by the experimental determination of the expansion curve of a bottom-hole sample.

The first experimental *P-V* curves to be published in this connexion were by Lindsly [7, 1933], followed shortly by May and Laird [10, 1934]. The experimental work involves:

(1) Drawing a bottom-hole sample of gas-saturated reservoir crude. Various instruments have been devised for this purpose and are described elsewhere in this volume.
(2) Confining a known weight of such sample over water or mercury at a predetermined temperature and observing the pressure curve as measured volumes of the water or mercury are removed from the apparatus.

In this connexion three factors have to be given careful consideration:

1. The Effect of Temperature.

Flow in a well is not isothermal. Reistle and Hayes [14, 1933] have published curves from East Texas showing

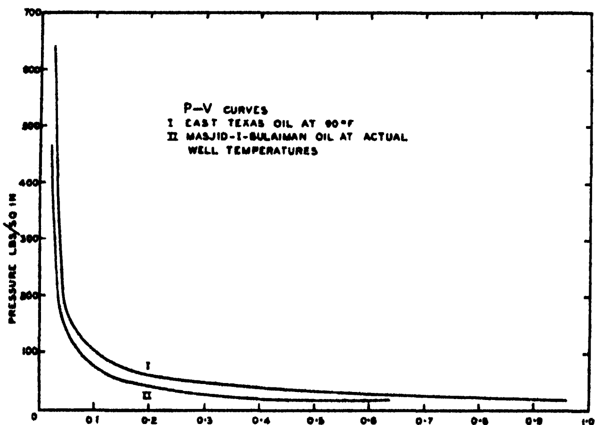

FIG. 4.

a temperature drop of some 70° F. over 3,000 ft. of tubing (Fig. 4). Moreover, the initial temperature at the bottom of a well is not necessarily constant over the whole of any one field. The general equation takes account of this variation, provided that the specific volume at any pressure is measured at the temperature obtaining at that pressure during flow. Theoretically, therefore, a series of isothermals should be determined covering the whole temperature range (cf. Lindsly [7, 1933]), and for any particular conditions of flow measure or estimate the pressure-temperature curve, subsequently drawing the corresponding *P-V* curve to intersect the isothermals. May and Laird [10, 1934], for the particular case of the Masjid-i-Sulaiman (Iran) field, found it sufficiently accurate to assume an average pressure-temperature curve, while Versluys [17, 1930] estimates that only in rare circumstances will the energy obtainable from gas expansion in a well vary by more than 0·5% from that calculated on the assumption of isothermal flow. Broadly speaking, the temperature drop over a given pressure range will tend to decrease with increasing ratio of oil to gas (due to the heat capacity of the oil) and also with increasing friction and slippage losses. The problem is one which needs to be studied for each individual field.

2. The Effect of Saturation Pressure.

Comins [1, 1933] and Pym [13, 1933] have shown that the saturation pressure (a measure of the dissolved gas content) may vary from place to place within the same reservoir. A whole range of *P-V* curves must therefore be constructed for any field in which this is found to be true—sufficient to enable accurate interpolation. It may be observed that while in any one field the saturation pressure may be taken as completely determining the *P-V* curve, it does not follow that such curves determined for one field can be applied to another where saturation pressures are similar—due to differences in the composition of the crude. In Fig. 5 are given representative *P-V* curves from Iran [10, 1934] and East Texas [14, 1933].

3. The Effect of Free Gas.

It has so far been assumed that the only gas involved in the flow is that dissolved in the crude under reservoir conditions. In fact, however, there is frequently free gas either drawn from the formation or added deliberately as in gas-lift. In either case the excess gas is usually lean and similar in composition to that dissolved in the oil under high reservoir pressures. The effect of such gas is therefore equivalent to a nominal increase in saturation pressure and may be allowed for by measuring *P-V* curves for samples of reservoir crude to which known amounts of excess gas have been added. There appears to be no record of any systematic work on these lines, apart from the experiments of Moore and Schilthuis [11, 1933], who claim that free gas gives a greater slippage loss than that evolved from solution (see below).

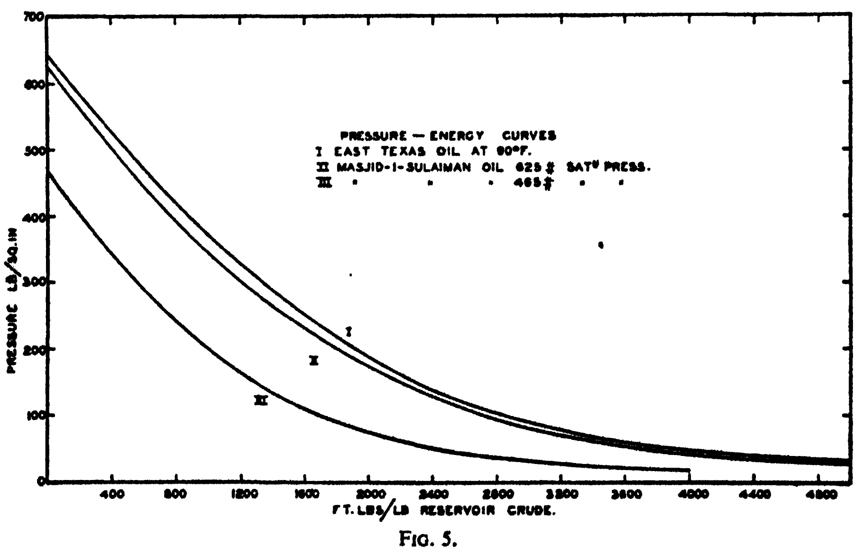

FIG. 5.

For experimental determinations of this kind the bottom-hole sample taker described by May and Laird [10, 1934] would appear to possess

considerable advantages. Alternatively it may usually be assumed that the excess gas is nearly pure methane, and if great accuracy is not desired an approximate calculation may be made of the effect on the *P-V* curve, using Raoult's law and Boyle's law with the usual corrections (including fugacity) at high pressure.

The subject of gas-lift is dealt with elsewhere in this work, and accordingly no further detailed reference will be made to it in this article.

Integration of *P-V* Curves

It will be observed from the general equation that if there are no energy losses,

$$144\,V\,dP'' = dh$$

or

$$144\int_{P_2''}^{P_1''} V\,dP'' = h_1 - h_2.$$

If the *P-V* curve is integrated between any two pressures, therefore it gives the height to which oil can be lifted if there is no waste of energy (Fig. 6). Both Moore and Schilthuis [11, 1933] and May and Laird [10, 1934] have found examples of flow in which energy losses were practically nil.

Other Physical Properties

It will be observed that the only other physical property explicitly mentioned in the general equation is the density. The quantities b and k may, however, depend also on viscosity and surface tension. Not only do all these properties differ from one reservoir crude to another, but for any one crude they all increase as the pressure falls and gas is evolved from solution. In none of the published work to date has any quantitative allowance been made for variations in these properties within a given flow system, and there is insufficient truly comparative data from different fields to determine with any accuracy the possible variations in the quantities b and k.

Pressure-depth Curves

The velocity of slip, b, and the friction factor, k, cannot be calculated theoretically, but are usually estimated indirectly as the result of experiments on the fall of pressure with height in a flowing well or some laboratory analogue. Such experimental work has been of three types:

(1) Measurement of pressure-depth curves in actual flowing wells with internal pressure indicator and comparison with the integrated general equation. This method has the advantage that there can be no question of differences between experimental and natural conditions, provided that the indicator is small enough not to interfere seriously with flow. For design of suitable instruments see article on 'Bottom-hole Pressure Measurement', p. 508, by Pym [22].

(2) Measurement of pressure-depth curves on short artificial gas-lifts with external manometers and comparison with general equation. This method as usually applied is open to the criticism that the lift is too short to guarantee that the state of subdivision of oil and gas is comparable with that occurring in normal flow.

(3) Moore and Wilde [12, 1931] carried out experiments in which, steady flow having been established in a short length of vertical casing and the overall pressure drop observed, the casing was isolated by simultaneously shutting valves at each end and the slippage estimated from the ratio of gas to oil found to be in the casing on the basis of a suitable modification of the general equation. The method is ingenious, but suffers from the same disadvantage as (2) above.

Typical pressure-depth curves are shown in Fig. 6; one from East Texas and three from Iran, these latter representing typical cases of

(I) Flow at 100% efficiency, i.e. no slippage, friction, or velocity head.

(II) Flow with high friction and velocity head losses. The effect of friction causes divergence from curve 1 at an increasing rate as the pressure falls, and below about 100 lb. per sq. in. the effect of velocity head causes a curvature in the opposite direction.

(III) Flow with high slippage losses. It will be observed that there is a sharp change of direction just below 100 lb. per sq. in. As explained below, at lower pressures the curve is identical with curve 1 at corresponding pressures, whereas at higher pressures there is considerable divergence due to slippage.

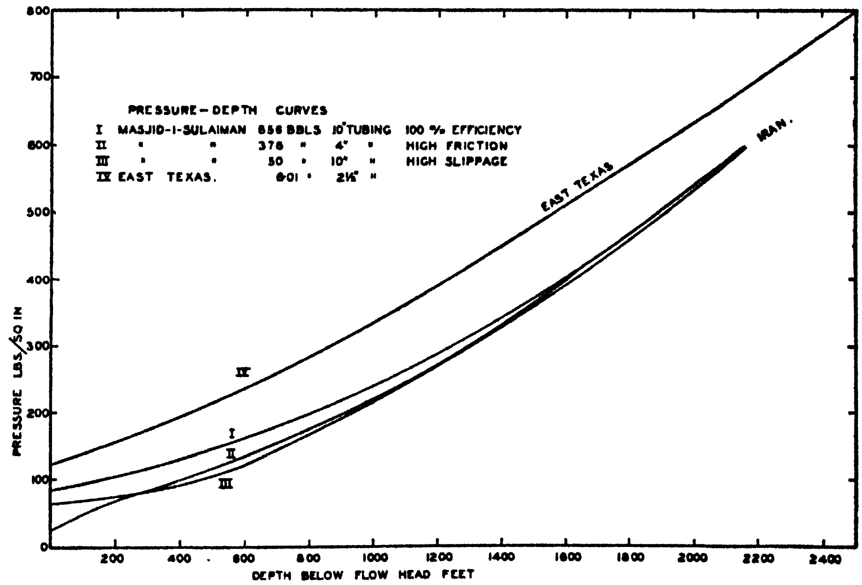

FIG. 6.

Evaluation of the Slippage Term

Versluys [17, 1930; 18, 1931; 19, 1933] has pointed out that slippage between gas and oil may occur in one of two states—'foam', in which bubbles of gas rise through a continuous oil phase, and 'mist', in which drops of oil fall through a continuous gas phase. The velocity of slip b will depend on which of these two conditions obtains and also on the size of the drops or bubbles, and the viscosity and density of the two phases. Versluys suggests figures of 0·66 to 1·0 ft. per sec. for the foam, and up to about 30 ft. per sec. for the mist condition. Versluys has further suggested that the foam condition is unstable at effective

gas/oil ratios of more than 1:1, while the mist condition cannot exist if this ratio is smaller.

Whether in the foam or the mist condition, the velocity of slip will depend on the size of the bubbles of gas or drops of oil. For example, in the case of a gas bubble rising through liquid the velocity increases as the size of the bubble increases with falling pressure. However, Stokes' law is only applicable so long as the bubbles remain spherical and are sufficiently small for flow round them to be stream-line. With increasing size the bubbles become flattened and flow becomes turbulent, so that ultimately a nearly steady velocity is attained.

In the lower parts of the well the total volume of gas out of solution is so small that the energy loss due to slippage is practically negligible. As it would be quite impracticable to take into account variations in the velocity of slip, for the sake of simplicity the value of b may be assumed to be constant without introducing appreciable error.

May and Laird [10, 1934], as a result of experiments in Iran, arrived at a value of about 0·5 ft. per sec. for the velocity of slip in what corresponds to Versluys' foam state. They, however, produced evidence to show that when the effective gas/oil ratio within the well reached about 1:1, slippage loss ceased abruptly, the gas and oil thereafter rising in the well with sensibly the same velocity (see Fig. 6, curve 3). In the general equation, therefore, they substitute a value of $b = 0{\cdot}5$ at all points until the specific volume reaches the value given by the equation

$$\frac{V^2\rho_L(w/Ab)+1}{V(w/Ab)+1} = 2,$$

and thereafter $b = 0$. Somewhat similar conclusions were reached by Moore and Schilthuis, who found that the experimental results of Moore and Wilde were not applicable on the large scale. They claim that dissolved gas on liberation from solution in a flowing well is in such a state of fine subdivision as to form a stable foam, but that any free gas is capable of slipping through this stable foam. Based on the small-scale experimental results, the following empirical equation was suggested by Moore and Wilde [12, 1931]:

$$y = \frac{3{\cdot}58\, D''^{1{\cdot}167} \rho_L^{3{\cdot}33}}{V'^{0{\cdot}67} \gamma^{0{\cdot}278}},$$

in which y is the ratio of the fraction of the pipe occupied by liquid to that occupied by gas (i.e. the reciprocal of the effective gas/oil ratio) and V' is a function of y, namely,

$$\frac{V'}{60} = q_g - \frac{q_o}{y}.$$

Moore and Schilthuis [11, 1933] proposed to use the same equation, but to substitute the density of the assumed homogeneous foam for that of the liquid, and to subtract from the total volume of free gas Q that part of it evolved from solution.

It may be observed that the theoretical basis of Versluys' argument for the instability of foams of high effective gas-oil ratio is unsound in so far as he assumes the spheroidal nature of oil drops and gas bubbles to be maintained throughout the expansion. There is no doubt whatever that the average crude oil is capable of forming a stable foam in which the bubble shapes are greatly distorted from the spherical probably up to gas/oil ratios of the order of 10:1. At the same time there are definite limits to the applicability of the formulae mentioned above, for discussion of which reference should be made to the original literature.

Mention should be made of two simplified methods of calculating slippage in special cases. May and Laird [10, 1934] point out that since in their experiments slippage ceases entirely at some relatively high pressure, the total energy lost in slippage is generally independent of the depth of the well and the flowing pressure. May [8, 1935] has therefore published a nomogram from which can be read directly the total slip loss for given conditions of flow—i.e. casing diameter, production rate, and saturation pressure. Even when there is 'mist' slippage near the top of the well, a nomogram of this type considerably reduces the work involved in calculation. Nomograms are also given by Moore and Schilthuis [11, 1933] for their empirical slippage and friction formulae.

Reistle and Hayes [14, 1933], dealing with the East Texas field, calculate the pressure drop in sections of finite length and, using Moore and Schilthuis' formulae, have plotted curves showing the fraction of the available energy usefully employed for various foam compositions and velocities.

Evaluation of the Friction Factor k

For the flow of a homogeneous fluid the friction factor is a function of the Reynolds number, $vD\rho/\eta$. In the case of a heterogeneous mixture it is difficult to ascribe a true value to the absolute viscosity, and experimental work is necessary to determine the variation of k with the other quantities.

Mention may be made of three sets of experiments.

(1) May and Laird's [10, 1934] experiments are not sufficiently extensive to determine the value of k without ambiguity. They, however, find it possible to calculate the pressure-depth curve over a 2,000-ft. well at a given rate of flow using a single value for k irrespective of the variation in composition of the oil-gas mixture with fall in pressure. The values obtained, moreover, are close to those derived from the ordinary Reynolds-Stanton curves for clean steel pipes if the value of $vD\rho/\eta$ is calculated for the reservoir crude before any gas is evolved from solution, i.e. it appears that $vD\rho/\eta$ is sensibly constant throughout the well and is equal to the value obtaining at the foot of the well. (See Article [21].)

(2) Moore and Wilde [12, 1931] did not find it possible to correlate their experimental data on the basis of the ordinary Reynolds theory and derive the empirical equation

$$dP'' = \frac{0{\cdot}0125\, v_F \rho_F \eta_L^{0{\cdot}18}}{D''}\, dh,$$

where dP'' is the pressure drop due to friction and the suffixes F and L refer to the foam and the liquid respectively. This equation is dimensionally unsound and the experimental accuracy does not appear sufficiently high to justify so radical a departure from conventional theory. (It should be noted that the value of the constant in this formula is variously stated in the literature—0·0125 [11, 1933; 12, 1931], 0·00125 [14, 1933].) The formula is equivalent to assigning a value to k of

$$\frac{1{\cdot}93\times 10^{-3}\, \eta_L^{0{\cdot}18}}{v}.$$

(3) Uren [16, 1930] and his collaborators find experimentally that k is inversely proportional to the velo-

city for the particular mixtures and flow rates used by them, i.e. they were working entirely in the stream-line region.

Summarizing the present position, it is evident that in order to determine the friction factor rationally in any given case, the right procedure should be, as in ordinary pipe-flow calculations, to estimate the effective viscosity of the fluid, hence calculate the Reynolds number and thence select the appropriate friction factor with due regard to whether the flow is stream-line or turbulent.

However, the data on which to base an estimate of the viscosity of a foam is very limited indeed. Two general effects due to the presence of gas bubbles can be recognized: (1) the lowering of the viscosity due to the displacement of a relatively high viscosity liquid by a very low viscosity gas; (2) the increase in apparent viscosity due to the resistance of the oil films between bubbles to distortion.

This effect is extremely complicated, and its value must depend not only on the gas/oil ratio, the bubble size, the surface tension, and its change in value on stretching, &c., but also on the rate of shear, since the foam has a certain inherent rigidity. (It has already been mentioned under the heading of 'slippage' that at high values of gas/oil ratio the bubbles are substantially distorted from the spherical shape while still being quite stable and resistant to slippage.)

When the viscosity of the oil is high the first effect is the greater, and a net lowering of viscosity takes place; for instance, Uren, Gregory, Hancock, and Feskov [16, 1930] found that with an oil of 580 centipoises at the flowing temperature, air-oil mixtures have effective viscosities ranging from 35 centipoises at 89:1 gas/oil ratio, to 8 centipoises at 1,070:1 gas/oil ratio.

All these viscosities were high enough to maintain stream-line flow in the 2-in. pipe even up to high velocities, so that the pressure drop was proportional to the velocity, or, in other words, the friction factor k varied inversely as the Reynolds number. In these experiments the gas/oil ratio was so high that the gas-oil mixture cannot have been in the form of a foam.

On the other hand, when the viscosity of the oil and the gas/oil ratio are relatively low it is generally recognized that the viscosity of a foam is greater than that of the oil, but there seems to be little or no data on this point suitable for estimating the value of the effect from the properties of the liquid.

As an example of this effect, in some unpublished experiments on Iran crude oil which had a viscosity under the conditions of flow of 3 centipoises, the apparent viscosity was found to increase to between 20 and 50 centipoises with gas-oil ratios of between 4:1 and 11:1.

These were calculated from the pressure drop in a tube about ½-in. bore at velocities up to 10 ft. per sec. The average bubble size was from 1 mm. to 3 mm. in all cases.

With the very meagre data available it is impossible to estimate the viscosity with enough accuracy to determine the friction factor, particularly as in the experiments of May and Laird [10, 1934] the use of the increased value of the viscosity mentioned above in the evaluation of the Reynolds number would lead to a much higher friction factor than was actually found. This is certainly a subject on which more experimental work is needed.

Practical Solution of the General Equation

Given values for the various physical quantities involved in the general equation, it is possible to calculate a pressure-depth curve for a well flowing under any given conditions. If the P-V relationship and the values of b and k can be expressed in simple mathematical terms, then a straightforward integration gives the relationship between pressure and depth. Such a formula has been derived by May and Laird for a particular case (Masjid-i-Sulaiman oil below 120 lb. per sq. in. abs.). The following, however, is the more general method.

First write the equation of flow in the form

$$dh = \frac{144\left(\frac{V^2w}{Ab}+\frac{1}{\rho_L}\right)dP''}{\left(\frac{Vw}{Ab}+1\right)\left(1+\frac{4kV^2w^2}{gDA^2}\right)} - \frac{\frac{Vw^2}{gA^2}dV}{\left(1+\frac{4kV^2w^2}{gDA^2}\right)},$$

i.e.
$$dh = C_1\,dP''-C_2\,dV,$$

where C_1 and C_2 have the values indicated above.

Now construct a table on the following lines:

1	2	3	4
V	P''	C_1	C_2

In column 2 fill in a series of values for the pressure, and in column 1 the corresponding values of V from the experimental P-V curves; calculate and tabulate the corresponding values of C_1 and C_2. Now plot columns 2 and 3 against one another and also 1 and 4. Integrate both curves by means of a planimeter between any desired values of P'' and the corresponding values of V. The difference between these two integrated values ($\int C_1\,dP''$ and $\int C_2\,dV$) for the particular set of limits chosen will obviously be the integral of dh between the same limits—that is, the actual lift. (Note that in most cases column 4 can be omitted without any appreciable loss in accuracy, since it merely represents the velocity head correction.)

The method is somewhat tedious, but is the most general available. It is noteworthy that most of the large-scale experimental work so far carried out has been confined to the rather specialized type of flow offered by the Iranian and East Texas fields, i.e. where the gas/oil ratio during flow is comparatively low. For such cases simplified methods of calculation have been suggested and referred to above. Any attempt at accurate calculation in other fields must be preceded by experiments to determine the type of flow and values of the various constants, for which purpose some such procedure as the above is essential. No useful purpose would be served in such an article as this in entering into details of various short cuts of possibly rather limited applicability.

Two points, however, may be mentioned.

In the first place it may again be emphasized that the integrated P-V curve is the pressure-depth curve for 100% efficient flow, i.e. no friction, slippage, or velocity head losses. It therefore forms a standard of comparison for actual flowing wells. Secondly, May and Laird [10, 1934] have provided an approximate method for calculating the pressure-depth curve in a well under given conditions of casing, size, and flow rate, given the curve for flow under the same conditions, but with oil of different saturation pressure. To a fairly close approximation the lift (allowing for friction and slippage) between the same two values of the specific volume is proportional to the saturation pressure. Reference should be made to the papers of May and Laird [10, 1934] and May [9, 1935] for further details.

Flow through Chokes

Some form of throttling is very generally used to control the flow of wells either at the bottom or at the surface. May and Laird [10, 1934] have pointed out that the flow of an oil-gas mixture at high velocities is similar to gas or steam flow with large pressure drops in that for a given initial pressure there is a certain maximum throughput attainable at an orifice, independent of the value of the back-pressure provided, only that it is below a certain critical value.

The formulae are derived in terms of the *P-V* curve and weight throughput. For small pressure drops:

$$w = \frac{12A}{V_2}\sqrt{\left(2g\int_{P_2''}^{P_1''} V\,dP''\right)},$$

where P_1'' and P_2'' are the pressures immediately above and below the orifice.

The maximum throughput is obtained by substituting in the above formula values for P_2'' and V_2 obtained from the equation

$$-\frac{2dV_2}{dP''}\int_{P_2''}^{P_1''} V\,dP'' = V_2^2.$$

This can only be solved graphically unless an exact mathematical formula is available for the *P-V* curve. Thus for the special case of M.i.S. crude with an initial pressure below 120 lb. per sq. in., May and Laird [10, 1934] find for the critical back pressure a formula independent of the saturation pressure

$$P_2'' = 0{\cdot}605\,P_1'' + 1{\cdot}975 \text{ lb. per sq. in. abs.}$$

These formulae assume a smoothly contracted orifice. For sharp-edged or other design of choke the appropriate contraction coefficient must, of course, be inserted (see article, 'The Laws of Fluid Flow in Pipelines' [21].

It is not the function of this article to detail the practical uses and advantages of bottom-hole chokes, for example, but the formulae have an obvious value in determining a minimum size of choke or off-take line for a given throughput.

Design of Flow Strings

Limits of space forbid any elaborate treatment of the various practical uses to which the scientific study of the flow of oil in wells can be put.

Variations in the conditions obtaining in different fields are such as to emphasize in turn the practical value of widely differing aspects of the main problem.

The question of the choice and design of flow strings, however, is one of universal interest and importance. If we consider the simplest case in which no free gas is drawn into the well with the crude, and for a given well and casing plot the flowing pressure against rate of production, the resulting curve will generally be found to exhibit a maximum. At higher rates of flow, friction, and at lower rates, slippage increase unduly and cause a fall in flowing pressure. (It should be noted that this effect may be masked by a high bottom-hole differential pressure, and care must be taken in interpreting results to ensure that this feature is taken into consideration.)

The position of the peak varies with casing diameter, and it is frequently desirable to determine the optimum size for a given rate of flow. Since there are only a limited number of standard casing sizes, the calculation of pressure drop described above for each of the various sizes available will solve the problem in this, the simplest of cases.

Complications, of course, arise if free gas is produced, since the gas/oil ratio is then usually not constant, but depends on the back pressure exerted on the formation. This subject is far too extensive to be dealt with within the limits of the present article, and obviously for the practical treatment experimental data is required for each well or type of well in a given reservoir. If such data is available in a suitable form, the calculation is somewhat more tedious, but follows the general lines described above.

It is sometimes considered desirable to use tapered flow strings—a small string at the bottom where the oil velocity tends to be low and the slippage high, increasing either in one or in several steps as the well is ascended and velocity increases and friction becomes of greater relative importance. Considerable doubt has been expressed by various authors (as, for example, Hayward [4, 1932]) on the advantages of the tapered string, it being held that the gain in efficiency over suitably chosen uniform tubing is so small as not to be worth while. This is a point which can easily be checked in any particular case by calculation. Various simplified methods have been suggested for designing tubing—in particular tapered tubing, of which two or three may be mentioned here.

Versluys [18, 1931] is primarily concerned with the difference between 'foam' and 'mist' slippage (see above), and considers that there is a region of unsteady flow at the change-over between gas bubbles in a continuous oil phase and oil drops in a continuous gas phase. In order to avoid this unsteady state he gives a chart of tubing sizes based on assumed velocities of slip and the concept of effective gas/oil ratios. The sizes are calculated to be either so small as to ensure the mist condition or so large as to ensure the foam condition. No quantitative account is taken of friction. Subsequent workers have indicated that the intermediate state is not, in fact, unsteady, since oil is capable of forming a stable foam. The charts, therefore, should be used with reserve.

May and Laird [10, 1934] suggest that slippage is negligible for oil of saturation pressure around 500 lb. per sq. in. and velocities of the order of 1 ft. per sec. and negligible also at effective gas/oil ratios greater than 1:1. A tapered string should therefore be designed to give a velocity of 1 ft. per sec. at the bottom and to be as large as possible at the top, provided that the effective gas/oil ratio is nowhere less than 1:1 in the larger tubing.

Moore and Schilthuis [11, 1933] calculate the value of dP/dh from the empirical formulae of Moore and Wilde [12, 1931] (see above) for various saturation pressures, rates of flow, actual pressures, and casing sizes. This is a convenient guide to the type of results that may be expected, and similar curves can be calculated once and for all for any particular field that is being studied, covering a suitable range of variables. Obviously that flow string is chosen for which dP/dh is a minimum. Moore and Schilthuis also give comparisons between uniform and tapered flow strings, showing an increase in efficiency of 5–10% in favour of the tapered string (cf. also [3, 1932; 8, 1933]).

Note on Unsteady Flow in Wells

The flow in wells can only be usefully calculated when the flow is steady, since the conditions during unsteady flow are so complex, and even the causes of unsteadiness are not well understood.

The main causes of unsteadiness no doubt originate in the well itself, but sometimes a well is found in which unsteady flow is initiated by some apparently trivial change

in the pipe work and connexions at some distance beyond the flow head even when conditions are adjusted to give the same rate of flow and mean flow-head pressure.

The most frequent basic cause of unsteady flow may be traced to conditions which prevent the throttling effect at the bottom or the top of the flow string itself exercising their normal control over the rate of flow.

Suppose that a well is severely constricted at the bottom so that oil containing gas in solution can enter relatively slowly at the foot, and suppose that initially the well is empty and the flow-head valve to be fully open. As the oil enters, gas will be evolved from solution, but the foam so formed cannot reach the top of the well, due to the small total quantity of oil in the well at the time. The well will gradually fill with oil; the gas evolved from solution as the oil enters the foot of the well bubbling up through the oil and escaping.

The oil column will in these circumstances be saturated at each point in the column to hydrostatic pressure, and this process could theoretically continue until the saturated oil column exactly balanced the hydrostatic pressure at the foot of the well, when no more oil would enter, and the well would be 'dead'. Now, particularly if the free oil-level is near the surface, this condition is clearly highly unstable and a very small disturbance will cause ebullition which will tend to initiate flow, causing a lightening of the column, which in turn produces more ebullition, until most of the contents of the well are ejected. The small residue of oil settles back and the well is then approximately in its initial condition ready for the process to be repeated.

The sequence of events outlined above is, of course, usually interrupted by the ebullition causing flow to start much earlier in the process, since the gas bubbling through the oil is a continual source of disturbance. The flow may also be checked long before all the oil has been ejected. The cycle may therefore have a long or a short period, but the principle is the same.

The mechanism may be described by saying that energy, in the form of oil with gas in solution, enters the well slowly, gradually accumulates, and at a certain stage this energy is liberated at a rate which is quite independent of the rate of supply.

Versluys [18, 1931] has suggested that one cause of unsteady flow is the change from the foam to the mist condition when the gas-oil ratio reaches a certain value given by Versluys as 1:1.

This change no doubt must occur at some value of the gas-oil ratio, but wells in Iran flow perfectly steadily at ratios of 10:1 and over.

Another similar source of unsteadiness is probably the coalescence of bubbles, so as to form eventually large plugs of gas, which will tend to slip through the foam, increasing in size on the way up the well. When they arrive at the flow head the rate of flow temporarily increases, due to the reduced density of the fluid passing through the flow-head valve.

The various methods of minimizing heading or surging come under the heading of production technique, and since it is generally agreed that the theoretical aspects are not at present amenable to scientific treatment, no useful purpose would be served by extending the discussion in the present article.

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THE CONTROL OF WATER IN OIL RESERVOIRS

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WATER is found in nearly all oil reservoirs. In most of them it serves as one of the sources of energy for the production of the oil, and when properly controlled, materially increases ultimate recovery. In any case, improper control of water will affect adversely both the recovery and the cost of operation.

Oil reservoirs consist of bodies of porous rock of varying degrees of permeability. Usually the rock is composed of sand, consolidated or unconsolidated, and sandy shale, but a number of reservoirs consist of porous limestone or dolomite, and a few of metamorphosed igneous rocks, granite wash, or other materials. Ordinarily, most producing sands have a permeability that falls within the range from 3 to 3,000 millidarcies. The methods of measuring permeability and the units used in expressing this quantity have been described by Fancher and co-workers [3, 1933] and Wyckoff and others [23, 1934]. In nearly every case, the permeability of a rock is greatest in a direction parallel to its bedding planes. Permeability varies throughout all oil reservoirs, but the variations are always more abrupt and of greater magnitude in a direction perpendicular than parallel to the bedding planes. Thus, movement of the fluids in the rock can, in most fields, take place more freely horizontally than vertically.

A. ROCK COMPLETELY WET BY WATER

B. ROCK PARTIALLY WET BY WATER

FIG. 1. Conditions at water-oil interface.

The pores of these reservoir rocks are filled with fluids under pressure. Generally, the upper portions of the reservoir contain free gas, below the gas lies oil and its dissolved gas, and beneath the oil, water is found. Before the reservoir is tapped by drilling wells, these fluids are in static equilibrium. Because of capillary forces, as pointed out by Garrison [4, 1935], the equilibrium position of the water-oil interface is not necessarily a level plane.

Capillary forces undoubtedly play an important part in the recovery of oil from the reservoir rock, but there are practically no quantitative data available on this phase of the problem. Water and oil wet most reservoir rock, but the tendency of the surface of the rock to adsorb these fluids varies with the nature of the rock surface and the fluid. The interface between these two liquids, when confined within the pores of the rock, is always concave toward the fluid having the least tendency to wet the rock. This is illustrated in Fig. 1. It is believed that in most cases, oil has less ability to wet the rock than water. Because of the interfacial tension, the surface between the water and oil tends to become as small as possible, and this tendency causes a pressure to be exerted on the fluid that has the least tendency to wet the rock. It may be shown that this pressure is expressed by the equation:

$$p_1 - p_0 = \frac{2I}{r'},$$

where p_1 is pressure on the concave side of the interface, p_0 the pressure on the convex side, I the interfacial tension, and r' the radius of curvature of the interface.

Because rocks of low permeability ordinarily have pores of small diameter, r' is, on the average, smaller in such rocks. Thus, the interfacial pressure differential is greater in rocks of lowest permeability. In the ordinary case, the permeability of the rock varies over wide limits. Therefore, for the establishment of static equilibrium the level of the interface in the various parts of the reservoir must adjust itself in such a manner that the interfacial forces are balanced by the hydrostatic pressure due to differences in density of the two fluids.

The difference in height between the non-capillary interface between oil and water and the equilibrium position of the interface is given by the equation:

$$h = \frac{2I}{(\rho_A - \rho_B)r'},$$

where h = the height above the non-capillary interface, I the interfacial tension, r' the radius of curvature of the interface, and $\rho_A - \rho_B$ the difference in densities between oil and water.

The nature of the surface of reservoir rock, and the interfacial tension between crude oil and water under reservoir conditions has not been investigated thoroughly, but measurements made on pure substances indicate that most reservoir rock is preferentially wetted by water. There are probably many important exceptions, but it is likely that in the majority of reservoirs water tends to displace the oil from the surface of the rock by capillary action. If this be true, it is obvious that the conception of a level plane of contact between oil and water under static equilibrium is incorrect except where the permeability is uniform. Instead, the level at which water is found depends upon the diameter of pore spaces in the reservoir rock, being higher in the less permeable rock having pores of small diameter. Furthermore, because of the irregular shape of the pores in reservoir rock, the boundary between the water and oil is not definite. Rather, there is a zone, containing both oil

and water, which separates the rock that is completely filled with water from that which contains a preponderance of oil.

After the reservoir is tapped with wells, as oil is produced, the pressure at the well bore is lowered, movement of the fluids occurs, and the static equilibrium is disturbed. Water tends to move into the space previously occupied by oil.

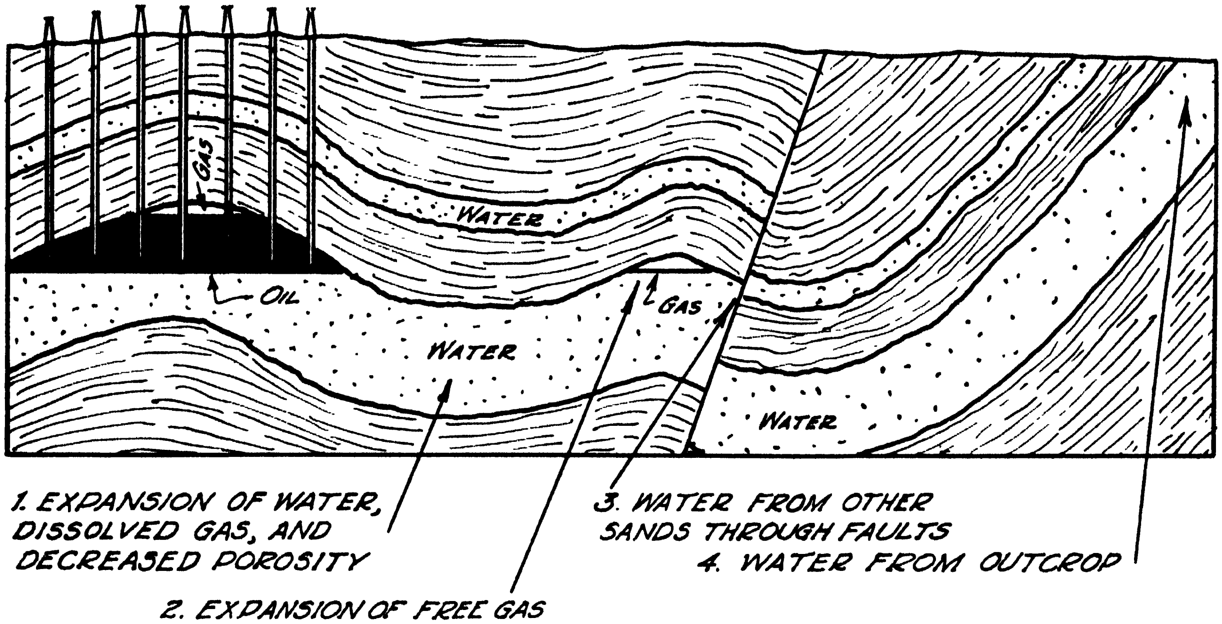

FIG. 2. Sources of water in oilfields.

One or more of the following may be responsible for the water entering the oil sand:

1. Expansibility of the water, which usually contains dissolved gases that can escape from solution upon reduction in pressure.
2. Expansive force of free gas bodies within the water-bearing portion of the rock.
3. Reduction in pore space of the rock upon reduction of pressure. This may be due to the elasticity of the rock, or to rearrangement of the particles, which may be accompanied by subsidence.
4. Supply of extraneous water, either at the outcrop of the porous formation, or from other formations through faults, &c.

Fig. 2 illustrates these possibilities.

The first three of these supply only such water as may have been in the water-bearing formation originally; the fourth is an extraneous source. Thus the sources of water within a reservoir result from the elasticity of the water itself with its dissolved gas, the bodies of free gas within the water reservoir, or the porous rock. Since the initial movement of water is due wholly, or to a large extent to the expansion of the water within the rock, Moore, Schilthuis, and Hurst [12, 1933] have pointed out that the unsteady type of flow prevails. In this type of flow the pressures and velocities at all points within the rock continually vary. Fluids move, under their own expansive power, from the higher pressure areas to the areas of lower pressure, their velocity being proportional to some function of the difference in pressure. At the same time, the density at any point is fixed by the pressure on the fluids at that point. Hurst [7, 1934] and Muskat [13, 1934] have developed the mathematics for this type of flow. The basic differential equation for this type of flow is, approximately:

$$\frac{\partial^2 \rho}{\partial x^2}+\frac{\partial^2 \rho}{\partial y^2}=\frac{c\theta\partial\rho}{K\partial\theta}.$$

x, y, and Z are the rectangular coordinates along which movement occurs, ρ the density of the fluids, c their expansibility, θ the porosity of the rock, and K the permeability. The important characteristics of this type of flow are, first, a higher velocity near the point at which the fluids are withdrawn, second, a fairly definite and continuously increasing zone in which appreciable reduction in pressure has occurred, third, a continuously decreasing pressure at the point of withdrawal, provided the rate of withdrawal is constant, fourth, the ability to restore the pressure, in some measure, near the point of withdrawal, when the rate of withdrawal is reduced. Fig. 3 shows the pressure relationships at various times for a constant rate of withdrawal.

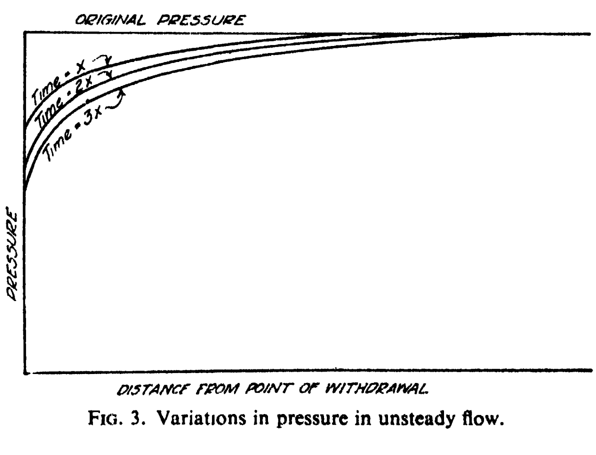

FIG. 3. Variations in pressure in unsteady flow.

In all oil reservoirs, the initial movement of water takes place by this mechanism, as pointed out by Herold [6, 1930]. Schilthuis and Hurst [16, 1935] and Moore [11,

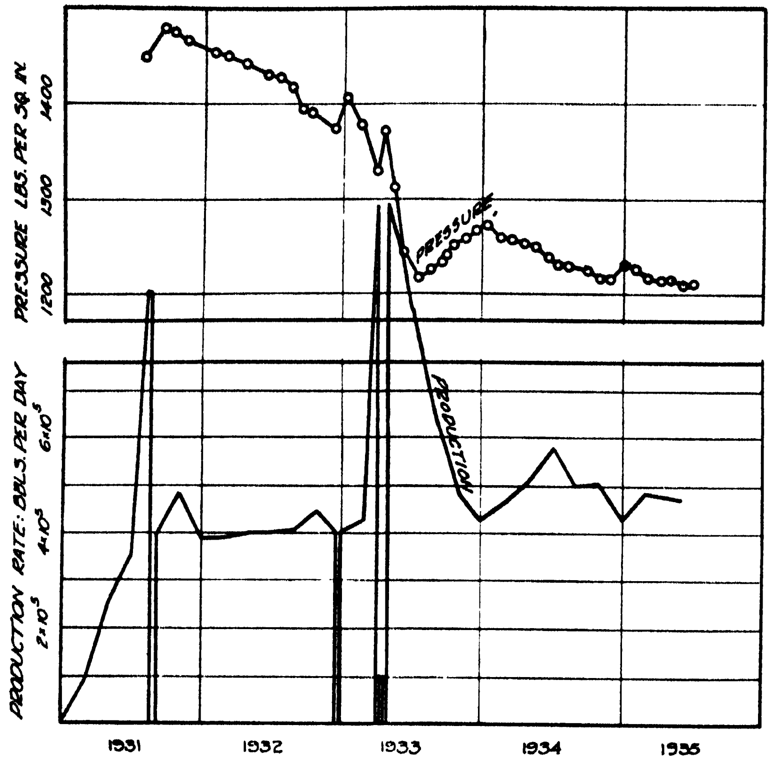

FIG. 4. Reservoir pressure and production rate, East Texas field.

1935] point out that in some fields, such as East Texas, all water entering the oil reservoir moves by this process, whereas in others, this movement soon becomes unimportant and of no practical significance.

Fig. 4 illustrates the pressure variations in the East Texas field, into which water has moved in sufficient quantity to fill all void spaces formerly occupied by the oil that has been produced, and in which the unsteady or transient type of water flow has prevailed. The slow decline in pressure at constant rates of production, and the increases in pressure that attend marked reductions in the rate of production are characteristic of the unsteady type of water encroachment.

Whenever, due to production, the pressure at a point where extraneous water may enter is reduced, there is a tendency to establish steady flow conditions. This type of flow is one in which the influx of water from extraneous sources exactly balances the withdrawal of fluids from the reservoir, and the pressures and velocities at any point remain constant, although they may vary from point to point within the water-bearing reservoir. Under this condition, the pressure at the point of withdrawal will remain at a constant value as long as the rate of withdrawal remains constant, and the pressure will be approximately a linear function of the rate of withdrawal.

True steady flow can be set up only when the supply of extraneous water is large compared with the rate at which the water must flow to replace the fluids and when there is little resistance to its movement to the oil reservoir. Herold [5, 1928] makes a distinction between the types of water flow when the supply of extraneous water is inexhaustible, which he calls 'hydraulic control', and when it is limited, which he refers to as 'volumetric control'. It is probable that in many oilfields, steady flow is approached, but never reached. In some, the flow may be unsteady, but the supply of water may be so great that the conditions of steady flow are closely approximated. The Sugarland field in Fort Bend County, Texas, is probably of this type, as may be seen from Fig. 5, which shows the variations in pressure that have occurred during the course of production. It will be observed from Fig. 5 that during the early part of 1932, while the production rate from the field was approximately 10,000 bbl. per day, the reservoir pressure was about 1,325 lb. per sq. in. Upon the reduction of the production rate in the fall of 1932 to 7,500 bbl. per day, the pressures rose to about 1,345 lb. per sq. in. and remained practically constant at this value for about 9 months. At

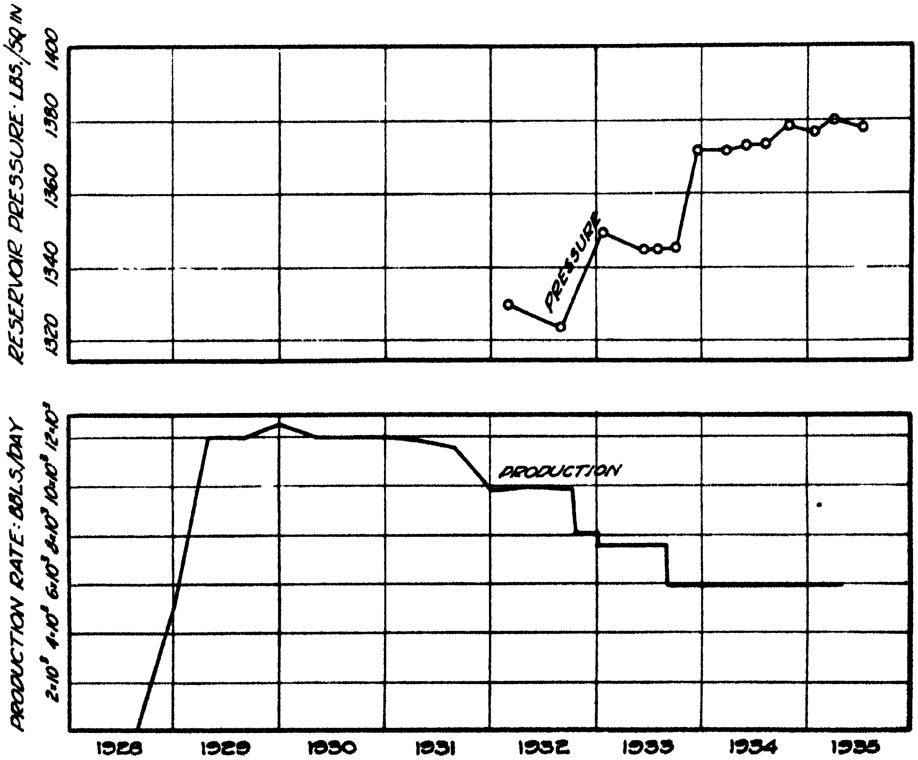

FIG. 5. Reservoir pressure and production rate, Sugarland field.

the end of this period, the production rate was again reduced. This time to about 6,000 bbl. per day. The pressures rose to about 1,377 lb. per sq. in. and have remained substantially constant at this value for more than a year. The fact that the pressures observed during the life of the field are so sensitive to the rate of production and that under a constant rate of production, the pressures are also found to be constant indicates that the field is acting as if water were entering it under steady flow conditions.

Many oil reservoirs are connected to water-bearing formations that have such a limited supply of water that no appreciable quantity of water can enter the oil reservoir. In such reservoirs, water may bring about serious production problems, but it can contribute nothing to increasing the oil recovery.

From the practical point of view, an understanding of the nature of the type of water flow is important in predicting the ability of the water to supply energy to the oil reservoir over long periods of time. The rate at which this energy can be supplied, regardless of the mechanism by which this occurs, is highly important in determining efficient rates of production in fields, and in the choice of operating methods.

The ability of the water to furnish energy for the production of oil is indicated by its tendency to maintain the pressure in the reservoir. The entrance of water compresses the remaining oil and gas in the reservoir and thus tends to maintain the reservoir pressure. The following equation gives the theoretical relationship between pressure and the production of oil and gas:

$$Z-z = qu+gv-qr_0v-G(v-v_0)-Q(u-u_0),$$

where

Z = total water that has entered field,

z = total water produced,

Q = total oil originally in reservoir,

q = total oil produced,

G = total gas originally in reservoir,

g = total gas produced,

u = specific volume of oil and its original store of dissolved gas, per unit of oil,

u_0 = specific volume of oil and dissolved gas under original conditions,

v = specific volume of gas,

v_0 = specific volume of gas under original conditions.

The various specific volumes depend on the pressure and temperature in the reservoir. Since the temperature remains substantially constant, they may be considered to be unique functions of pressure:

$$u = f(p)$$
$$u_0 = f(p_0)$$
$$v = \phi(p)$$
$$v_0 = \phi(p_0),$$

where p_0 is the original pressure and p the pressure after the production of g units of oil. The form of the functions f and ϕ can best be determined by examination in the laboratory of samples of the oil and gas taken from the bottom of wells under pressure, as Lindsly [8, 1933] and Schilthuis [15, 1935] have done.

Substituting:

$$Z-z = qf(p)+(g-qr_0)\phi(p)- \\ -G[\phi(p)-\phi(p_0)]-Q[f(p)-f(p_0)].$$

Differentiating with respect to time, θ, and rearranging,

$$\frac{dZ}{d\theta}+(Q-q)\frac{d[f(p)]}{d\theta}+[G-(g-qr_0)]\frac{d[\phi(p)]}{d\theta} \\ = \frac{dz}{d\theta}+f(p)\frac{dq}{d\theta}+\phi(p)\frac{d(g-qr_0)}{d\theta}.$$

The terms on the left-hand side of this equation are the rate of change in volume of the three fluids present in the reservoir: water, oil with its dissolved gas, and free gas, respectively. The rate of withdrawal of these fluids constitute the right-hand terms.

In fields under an active water drive, $dZ/d\theta$ is large. To balance the equation, $d[f(p)]/d\theta$ and $d[\phi(p)]/d\theta$ are small. Conversely, if $dZ/d\theta$ is small, $d[f(p)]/d\theta$ and $d[\phi(p)]/d\theta$ are large. This means that water encroachment retards the rate of pressure decline, and also, as Moore [10,1933] points out, that the power of water to maintain pressure depends upon the volumetric withdrawal (rate of withdrawal of all fluids, expressed as volumes under reservoir conditions rather than upon withdrawal of oil alone). Because of inherent difficulties in measuring true average reservoir pressure, this equation cannot be applied rigidly in the field. However, it does show qualitatively the effect of water intrusion and production of water on the maintenance of pressure.

The pressure conditions in the reservoir tend to approach the steady state, under which there is no change in pressure. Under these conditions, $d[f(p)]/d\theta$ and $d[\phi(p)]/d\theta$ are zero, and

$$dZ/d\theta = \frac{dZ}{d\theta}+f(p)\frac{dq}{d\theta}+\phi(p)\left[\frac{d(g-qr_0)}{d\theta}\right].$$

Or, the rate of water encroachment is equal to the volumetric withdrawal. This equation may be used in estimating approximately how fast water is entering fields in which the pressure is remaining substantially constant. The following table gives an estimate of this quantity on some of the fields on which data are available:

	East Texas	*Conroe, Montgomery Co., Texas*	*Thompsons, Ft. Bend Co., Texas*	*Sugarland, Ft. Bend Co., Texas*
Initial pressure, lb. per sq. in.	1,625	2,275	2,430	1,570
Producing pressure, lb. per sq. in.	1,225	2,090	2,345	1,375
Pressure difference, lb. per sq. in.	400	185	85	195
Production rate, bbl. per day	430,000	43,500	12,000	6,000
Volumetric withdrawal, bbl. per day	535,000	70,400	15,070	5,200*
Water entering per day, bbl.	535,000	70,400	15,070	5,200
Water entering per day, bbl. per lb. pressure difference	1,340	380	177	27

* Repressuring.

All of the fields listed are under active water drive, yet in order to take advantage of the power of the water to maintain the reservoir pressure, the fields must be produced at low rates. Slow rates of production permit the oil to be produced from water-drive fields with low expenditure of reservoir energy. However, it is the volumetric withdrawal, and not the oil production, that determines the extent to which the pressure will be maintained by water drive. Thus, every effort should be made to reduce to a minimum the production of free gas and water.

Because it has in most cases a greater tendency to wet

the reservoir rock, water displaces the oil film from the rock, and tends to increase ultimate recovery. However the encroachment of water should be kept as uniform as possible in order to avoid the difficulties that attend producing large quantities of water, to conserve the energy that would be lost by excessive water production, and to prevent a loss of recovery due to the isolation of large bodies of oil by encroaching water.

There are at least four types of irregular water encroachment:

1. Irregular encroachment due to increased linear velocity of fluids in the vicinity of well bores.
2. Irregular encroachment due to differences in permeability of the reservoir rock.
3. Irregular encroachment due to the structural condition of the reservoir.
4. Irregular encroachment due to improper completion of wells.

'Coning' and 'fingering' are the most common types of encroachment due to increased linear velocity near the well bore. These phenomena have been analysed theoretically by Wyckoff and his co-workers [22, 1933]. Fig. 6 shows how a water front advances towards a producing well. It is readily seen that water reaches the well long before all of the oil has been flooded out.

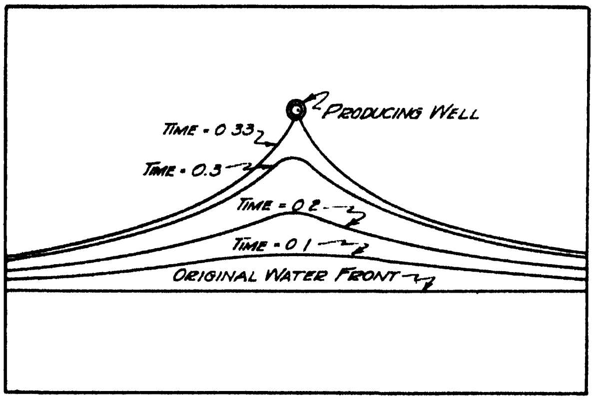

FIG. 6. Advance of water to a producing well.

Coning is the intrusion of water into a well from water sands directly below the well, a phenomenon that has also been studied by Wyckoff [24, 1935]. Due to the lowered pressure at the well bore, the water tends to move toward the well. The level of the water under the well rises, and takes the shape shown in Fig. 7. The pressure gradients around the well tend to draw the water into the well; the difference in density between the water and the oil tends to maintain the water-oil interface level. If the rate of flow is kept sufficiently low, the water cone assumes an equilibrium shape under which the frictional and gravitational forces are in balance. However, there is a critical rate of flow above which the cone cannot assume a position of equilibrium, and water then flows into the well. The effect of the rate of flow on the height of the water cone is shown for a typical well in Fig. 8. The critical rate of flow depends on the thickness of the oil sand, its permeability, and the penetration of the well. Lenses of shale or tight sand between the bottom of the well and the water reduce the coning tendency to a great degree.

It is doubtful if, in most fields, either coning or fingering is as important as the differences in permeability of the rock in causing irregular encroachment of water. Wilde and Lahee have made a study of this matter [21, 1933]. There are two kinds of forces causing irregular movement:

1. The different resistance to flow in beds of different permeability.
2. The different capillary forces.

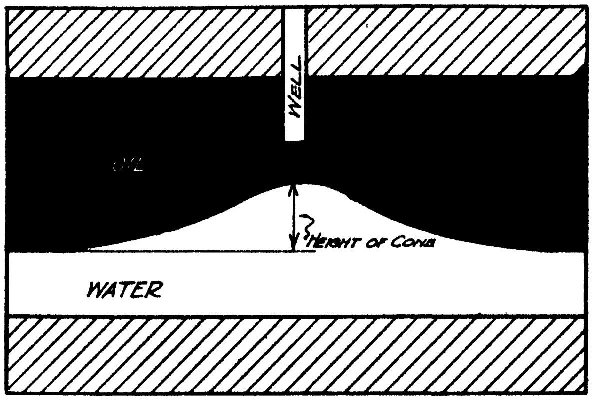

FIG. 7. Water cone.

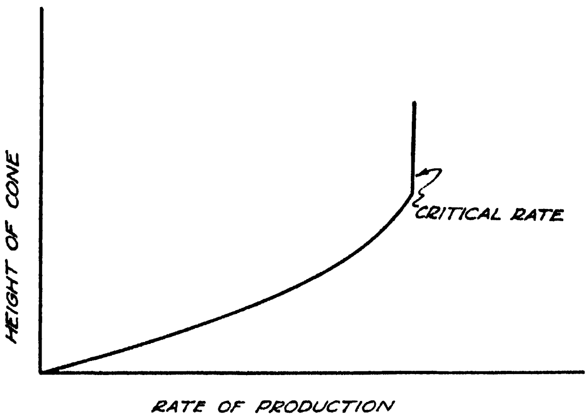

FIG. 8. Effect of rate of flow on height of cone.

Ordinarily, there is a tendency for the fluids to move with greater velocity in the sand of greatest permeability. Wherever interfacial and gravitational forces may be neglected, the water-oil interface advances most rapidly in these sands. However, the interfacial forces tend to move oil out of the less permeable sands into those of greater permeability, as was shown in the earlier discussion. Furthermore, the action of gravity tends to retard water movement in that portion of the sand in which the water has advanced higher than its position of static equilibrium. Thus the forces influencing the rate of water intrusion are:

1. The frictional resistance, which tends to retard the motion through the less permeable sand.
2. The interfacial forces, which tend to accelerate the motion in the less permeable sand.
3. The gravitational forces, which generally tend to retard motion through the sands of greater permeability.

If the rate of production be low, so that the interfacial and gravitational forces are large in comparison with the total pressure drop, water movement in the less permeable sands is more rapid in comparison with that in the more permeable sands, and the encroachment of water becomes more regular. This is shown in Fig. 9, A, B, and C. The first of these illustrates a condition of static equilibrium in two sands

of different permeability. The second shows how the water advances more rapidly in the more permeable sand at higher rates of flow, while the third shows how lower rates of flow tend to retard the advance of water in the more permeable sand with respect to the less permeable sand.

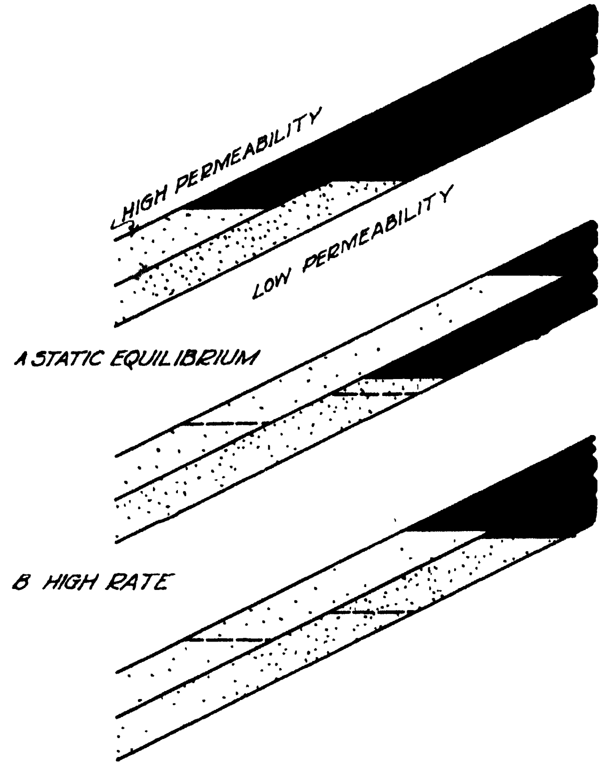

FIG. 9. Effect of rate of flow on movement of oil and water in sands of different permeability.

The velocity at which the water replaces oil is influenced by the dip of the formation, the permeability, the pressure gradient, and the interfacial force. When the pressure drop due to friction is of the same order of magnitude as the interfacial and gravitational forces, the velocity is governed to a great extent by these forces. At higher velocities, friction is the major factor that controls velocities, and the velocity becomes substantially proportional to the permeability. The practicability of controlling irregular water encroachment by low production rates depends entirely on whether or not a reasonable rate of production can be secured with a pressure drop so low that frictional effects do not overshadow the interfacial and gravitational forces.

Irregular encroachment is occasionally due to the structure of the reservoir. Often water may move upward along a permeable fault plane, entering a permeable producing rock at a point much higher than the normal water level, and channel to wells. This is illustrated in Fig. 10.

Irregular encroachment is sometimes due to improper completion of wells, or poor cementing. Its action is somewhat similar to migration of water along fault planes.

Irregular encroachment can be controlled to a large extent by a reasonably low rate of production. Where feasible, this is by far the most efficacious and economical method of accomplishing this. However, in many instances, water production from oil-wells cannot be controlled by rate of production alone; in these cases, mechanical methods of plugging off water must be employed.

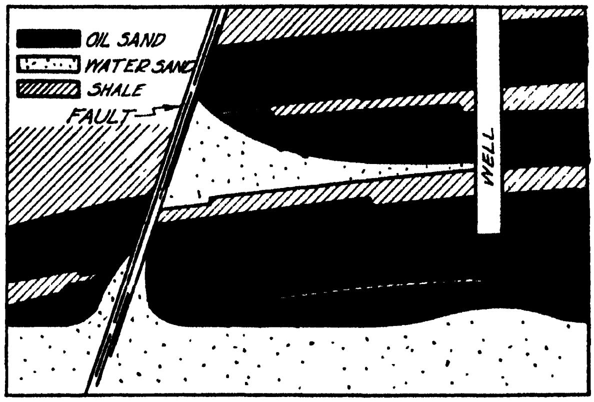

FIG. 10. Irregular water encroachment through fault.

To plug off water successfully, it is necessary to determine at which point the water enters the hole. There are two methods commonly used for this purpose, both of which depend on the measurement of electrical resistance.

The first method, described by Robinson [14, 1931], measures the resistivity of the fluid in the hole. In practice, the hole is first filled with a fluid whose resistivity is quite different from that of the water expected to flow into the hole. Usually either fresh-water or a strong salt solution is used. A conductivity cell is then run into the well, and the resistivity of the fluids is measured. At the point at which water enters from the rock, the fluid in the well is changed in composition, which shows up as a change in the resistivity.

The second method is that developed by Schlumberger [2, 1935; 17, 1933], and is widely used in correlating and determining the character of the formations while drilling wells. It is essentially a method of measuring the resistivity and porosity of the rock. Three electrodes are run on a cable. A circuit is set up through the rock between the lowest electrode and a ground at the surface. Most of the current flows through the earth; therefore, the position and shape of the equipotential surfaces depend upon the resistivity of the rock. Two electrodes are suspended above the lower electrode and means are provided for measuring the potential difference across these, which is approximately proportional to the resistivity of the rock. The so-called 'porosity' is determined by observing the changes in potential that are set up as the mud fluid tends to flow back into porous formations. The variations in the potential of one electrode are noted, high potential being an indication that the formation is porous. A sand with high resistivity and high porosity indicates that the pores contain oil or gas, while low resistivity and high porosity indicates that the sand contains salt-water. The method has been widely used with outstanding success.

Having located the water, it is important to plug off the water sand. Usually, this is accomplished by plugging back to and including the highest water sand, although recently more attention has been given to plugging only the water sands.

Cement is the most widely used material for plug-back operations, although in some areas in which cable tools are employed, lead wool is driven into the lower portion of the hole to pack off the water sands.

Common methods of cementing off water sands are:

1. The dump-bailer method.
2. The pump-and-plug method.
3. The balanced-column method.
4. Pumping cement into water-bearing formations.

The dump-bailer method as described by Tough [18, 1918], is one of the earliest methods used in plug-back operations, and is still employed in many cases, especially where cable tools are used. It consists in placing the cement with a bailer, which is constructed so that its load may be discharged when the bailer is on bottom. One type of dump bailer is shown in Fig. 11. When running into the hole, the weight of the bailer is supported by the sand line which is attached to the valve. When the bailer reaches bottom, the line is slacked off, permitting the rod to pass through the bottle-neck at the top of the bail. A latch on the rod engages the bottle-neck, and when the bailer is picked up, the weight is supported by the latch. This permits the valve to open, dumping the bailer.

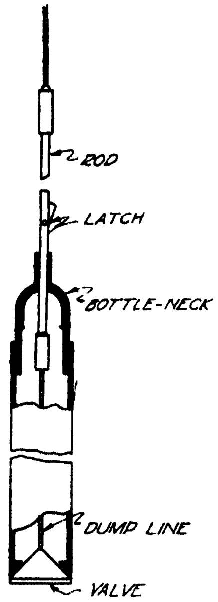

FIG. 11. Dump bailer.

Cementing through tubing is a more common and generally a more satisfactory method of plugging back. This may be accomplished by several methods. One of these consists in running a blank string of tubing to within about a foot of bottom, and washing the well until clean. A wooden plug, about 2 ft. long, is

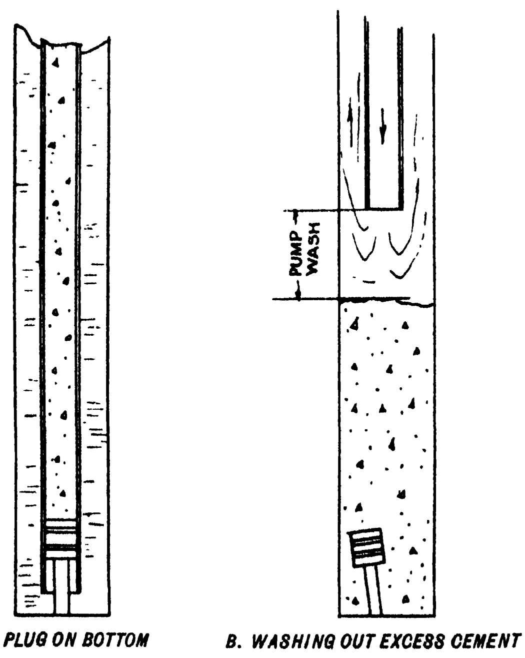

FIG. 12. Plugging back through tubing.

then placed in the tubing, and cement is pumped behind the plug. Water is then pumped behind the cement until the plug strikes bottom. The tubing is then raised the required distance, after allowing for pump wash, and the excess cement is washed from the hole. Fig. 12 shows diagrammatically the conditions at the bottom of the hole while the plug is on bottom and while washing out the excess cement.

An interesting variation of this method has recently been developed and used successfully in Central Texas by Watson [20, 1935]. The tubing string is shown in Fig. 13.

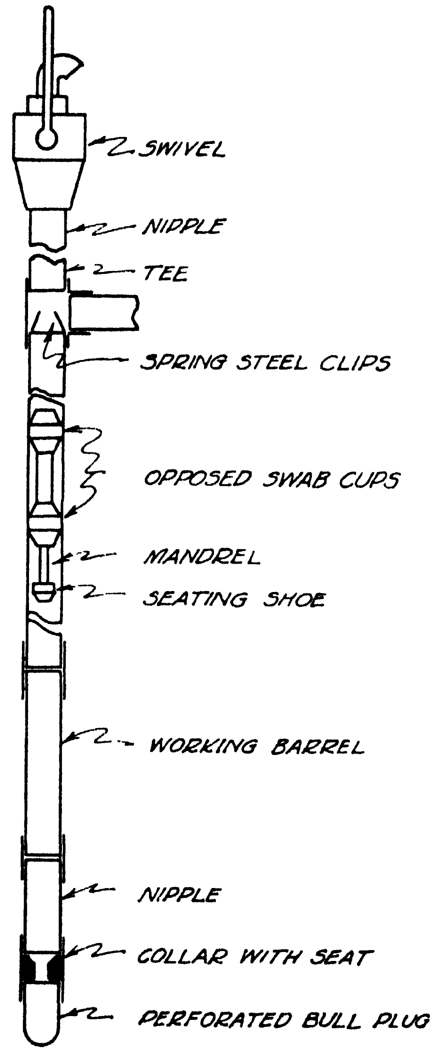

FIG. 13. Equipment in Watson's method of plugging back.

At the bottom of the tubing is a perforated bull plug. A short nipple and a working barrel are run just above the bull plug. The cement plug consists of two opposed swab cups on a mandrel and seating shoe. The well is washed thoroughly, and then the cement is pumped into the tubing, followed immediately by the cement plug. Water is pumped in until the plug hits bottom, when the pump stops. Thus, all cement is forced out of the tubing. The tubing is then raised the required distance, and by reverse circulation, the plug is pumped up the tubing, where it is caught in the nipple between the tee and the swivel by spring-steel clips. After washing until the excess cement is removed, the tubing is raised a short distance and the cement allowed to set. An insert pump may be run, and the well tested without pulling the tubing.

The balanced-column method is widely used in the Texas

Gulf Coast and does not require the use of plugs. The hole is filled with mud, and a carefully measured volume of water is pumped down the tubing. This is followed by the required volume of cement, then by a volume of water such that the length of the slug of water that follows the cement in the tubing will equal the length of the slug that preceded the cement in the annular space. Thus, when the cement is in place, the level of the cement and the water is the same both inside and outside the tubing, as shown in Fig. 14. By carefully noting the pump pressures, the pumps may be stopped very close to the balanced position. The tubing is then raised the required distance, allowing 1 or 5 ft. for pump wash, and the hole is washed clean.

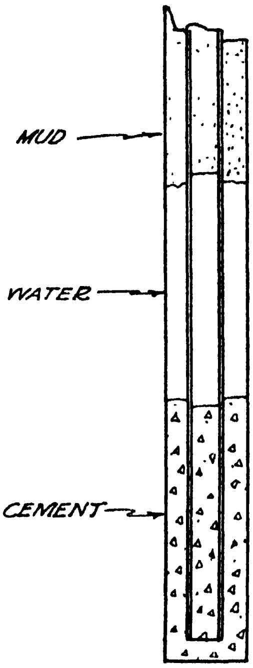

Fig. 14. Balanced-column method of plugging off water.

One method that has been recently used successfully consists in pumping a thin cement slurry back into the formation. The cement slurry is pumped into the hole until it is approximately opposite the water sand to be plugged, the blowout preventer is then closed, preventing any fluid flow through the annular space, and water is pumped behind the cement, forcing it into the sand. After sufficient cement is pumped in, the blowout preventer is opened, circulation re-established, and the well washed clean. This method has had one or two remarkable successes, but has not been used long enough to determine whether or not it will be generally applicable.

Vietti and Oberlin [19, 1928] have shown that the control of the cement slurry is important in successful plug-back work. Usually a slurry of a density of 16 lb. per gall. is used, although for pumping the slurry back into the formation, this is reduced to about 14 lb. per gal. Cement of good quality should always be used, it should be carefully mixed, and every precaution should be taken to prevent mud contamination. Where there is danger of salt-water contamination in the well, better results can be obtained by using the well water to mix the cement. A bulletin distributed by the Baroid Sales Company [1, 1934] claims that in some cases the addition of small amounts of bentonite to the cement is advantageous where it is desirable that a gel structure should form quickly in order to maintain the position of the cement until it has had an opportunity to set.

In addition to cementing, various chemical methods, such as that of Mills [9, 1922], have been proposed to shut off water, but none of these have ever been used with consistent success. However, it appears that such methods can be developed, and they are likely to have many advantages over cementing.

Summary

1. The proper utilization and control of water is one of the most important of the problems in petroleum production.

2. The control of water is complicated by the variations in permeability of the reservoir rock.

3. At the water-oil interface, capillary forces are important. Usually these forces act to displace the oil with water. The magnitude of these forces depends on the permeability of the rock, being greater in the less permeable sands.

4. Water is present in practically all oil reservoirs. As the pressure in the reservoir is lowered, water tends to move in to replace the oil.

5. The first movement of water takes place by expansion of the water and its associated fluids. While this expansion is of little importance in some fields, in others it is sufficient to supply all of the energy required for the production of oil.

6. As the expansion of the water progresses, the pressures in the water-bearing rock become lower at greater and greater distances from the oil reservoir.

7. When the pressure has been reduced at the outcrop of the productive formation, or at some other point at which extraneous water may enter, there is a tendency to set up a condition of steady flow, that is, one in which the supply of extraneous water balances the fluid withdrawal from the field.

8. Water entering the field tends to maintain the reservoir pressure.

9. The faster the rate of flow, the less is the ability of the water to supply energy to the reservoir to maintain pressure. By properly controlling the rate of production, many fields may be produced without appreciable decline in pressure.

10. The harmful effects of water are generally due to irregular encroachment, often brought about by improper control.

11. Coning of bottom-water and fingering of edge-water are examples of irregular encroachment.

12. Irregular encroachment of water due to differences in permeability is the most serious cause of underground waste due to water.

13. Interfacial forces tend to displace oil from the less permeable sands; frictional resistance causes more rapid movement in the more permeable sands. In many cases the rate of flow may be reduced to the point where the interfacial and gravitational forces are important factors. When this can be accomplished, more regular movement of water results.

14. Irregular encroachment is sometimes due to movement along fault planes or to improperly completed wells.

15. Excessive production of water is harmful. Waste of reservoir energy and exclusion of oil from the wells is brought about.

16. Wherever possible, water should be shut off in producing wells. This is usually accomplished by cementing, either by the dump bailer or by cementing through tubing.

17. For maximum economic recovery, full advantage should be taken of a natural water drive. Every effort should be used to avoid excessive water production, and the field should be produced at such a rate that the water can supply most of the energy used in producing the oil.

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OILFIELD REPRESSURING

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THE repressuring of oil sands is supposed to have had its beginning in the Macksburg Pool, Ohio, in 1903, when I. L. Dunn forced gas under pressure into an oil-well and then released the pressure [9], which action was accompanied by a much greater production of oil than had been extracted prior to the injection of the gas. In 1911 Dunn was successful in increasing production in another field in Ohio by forcing compressed air through the oil sands. Progress during the following 5 or 10 years was not rapid, and practically all experiments and operations were confined to the Appalachian group of oil-producing states. In 1924 mention is made only of small repressuring operations in Oklahoma, but in 1926 there were about 110 plants operating, or in process of erection, in Kansas, Oklahoma, and Texas, for the purpose of repressuring partly depleted oilfields.

The three methods employed whereby use is made of injecting compressed air or gas into an oil sand are as follows:

1. Pressure maintenance, in which, by injection of gas, the pressure in the reservoir is held at a point as near as possible to the original pressure.
2. Pressure restoration, or repressuring, in which gas is injected into the oil sand until the original pressure has been restored.
3. Gas drive, or pressure drive (commonly called repressuring), in which compressed air or gas is circulated through the sand for the purpose of sweeping oil along with the gas to the producing wells.

Up to the year 1928, most of the operations of a repressuring nature consisted of the injection of air or gas under pressure into the oil sand, through input wells, for the purpose of stimulating production in surrounding wells. The first successful attempt to inject gas under very high pressure into a sand was done in the Seal Beach field, California, in 1927 [6], where gas under pressure as high as 1,850 lb. per sq. in. was injected into the reservoir, and very shortly afterwards the action was rewarded by increased production in neighbouring wells. The pressure was shortly afterward reduced to 1,400 lb.

Pressure Maintenance

The method of pressure maintenance was not undertaken in a serious way until the year 1928, when operations were started in the Pendopo field, Sumatra [11, 1934], and in 1930, when similar operations were begun in the Sugarland [14, 1930] and Raccoon Bend [8, 1931] fields, Texas.

The idea of pressure maintenance appears to have been conceived several years previously by H. L. Doherty, who applied for patent in 1925 [4], covering the method, which patent was granted in 1933. This method was also suggested by C. S. Corbett [3] in a paper presented in 1930 before the Tulsa meeting of the A.I.M.M.E.

The pressure maintenance project at Sugarland was made possible by reason of the fact that the entire pool was controlled by a single operator. A plan was formulated for returning to the sand all the gas that was produced with the oil with the exception of that required for general lease purposes. The preliminary outlook as to the objects to be accomplished was as follows [14, 1930]:

> 'It is not thought that pumping of wells will be necessary in the Sugarland field, and theoretically when all of the possible oil is produced the structure will remain practically a dry gas reservoir. Also it is thought that the return of the gas to the sand at practically the original field pressure will retard or stop the intrusion of water until the oil is recovered and the operations start draining the remaining gas reservoir.'

The work at Sugarland has continued to the present time. Results of two different periods are given in Table I.

TABLE I

Data on Pressure Maintenance Operations in the Sugarland Field

	Aug. 1930		*Nov. 1934*	
	During August	*Since April 1930*	*During Nov.*	*Since April 1930*
Oil produced, bbl.	371,479	1,799,015	179,995	15,147,793
Gas produced, M. cu. ft.*	95,856	471,426	46,385	4,378,349
Gas injected, M. cu. ft.*	87,018	415 235	41,082	3,869,605
Gas returned, %	90·8	88·1	88·7	88·4
Gas/oil ratio, cu. ft. per bbl.*	258	265	258	289
Injected gas/oil ratio	234	232	228	255
Net gas/oil ratio	24	33	29	34

* On 2-lb. pressure base.
Estimated original pressure was 1,570 lb. per sq. in.
Reservoir pressure, April 1930, was 1,280 lb. per sq. in.
Reservoir pressure in Nov. 1934 was 1,380 lb. per sq. in.

The estimated ultimate recovery in the Sugarland field has been placed at 86,123,000 bbl., and up to the end of December 1934 total recovery had amounted to 21,000,000 bbl.

The presssure maintenance work at Raccoon Bend has not produced quite as favourable a result as that at Sugarland. Operating results in this field are given in Table II.

TABLE II

Data on Pressure Maintenance Operations in the Raccoon Bend Field, Texas

	Nov. 1934	*Since pressure maintenance started, July 1930*
Oil produced, bbl.	104,367	8,661,567
Gas produced, M. cu. ft.*	151,199	13,128,861
Gas injected, M. cu. ft.*	91,959	6,773,874
Gas returned, %	58·5	51·5
Gas/oil ratio, cu. ft. per bbl. produced*	1,449	1,516
Injected gas/oil ratio, cu. ft. per bbl.*	881	782
Net gas/oil ratio, cu. ft. per bbl.*	568	734

* 2-lb. pressure basis.

Ultimate recovery in the Raccoon Bend has been estimated at 29,000,000 bbl. Up to the end of December 1934 the recovery had amounted to 13,500,000 bbl.

Pressure Restoration

The only example of actual repressuring, or pressure restoration, of which the writer has any knowledge, is that at Olney, Texas, where the Humble Oil and Refining Company restored the pressure nearly to the figure originally existing in a field that had been almost depleted [15, 1930]. The area consists of 60 acres on which 21 producing wells were drilled, spaced about 300 ft. apart. The recovery had amounted to 349,140 bbl., and the production had declined to 2 or 3 bbl. per well per day, or almost to the economic limit at which time the pressure was approximately zero-gauge pressure. For some time before production was suspended, vacuum had been applied. The work of restoring the pressure was started in 1930, and 109,000,000 cu. ft. of gas were injected, raising the pressure over the area to an average of 354 lb. The field was allowed to stand until November 1931, at which time production was begun. No additional gas has been injected since that time, only the gas produced with the oil being returned to the reservoir. Since May 1934 a little over 1,000,000 cu. ft. of gas per month have been withdrawn from the reservoir for use as fuel. The reservoir pressure in November 1934 was 199 lb. per sq. in. Data on operations in the field since this project was started are as follows:

TABLE III

	Nov. 1934	Since repressuring was started
Oil produced, bbl.	2,562	122,105
Gross gas produced, M cu. ft.	30,498	..
Gas injected, M. cu. ft.	29,163	..
Net gas produced and lost, M. cu. ft.	1,335	9,236
Gas returned, %	95·5	91·5
Additional oil recovery, %	0·73	35·0
Net gas/oil ratio, cu. ft. per bbl.	520	76

The work at Olney is a good example of the results that can be achieved when skill and patience are employed in handling an experimental project.

Partial pressure restoration had a beginning in the Dominguez field, California, in 1925, when the Union Oil Company and the Shell Oil Company began injecting gas into the field. The scope of the work was increased in 1928 to the point where some of the wells were returned to natural flow, these wells having been artificially produced before the repressuring operations were started [10].

Partial repressuring has been carried on in the Infantas-La Cira field, Colombia, but data on the operations are not available. Gas drive and pressure restoration have been employed at La Brea-Parinas field, Peru, and at the present time, approximately 22,000,000 cu. ft. of gas per day are being injected into the various pools [7, 1924]. Up to the present time, the total quantity of gas returned to the reservoirs in Peru has aggregated 38 billion cu. ft.

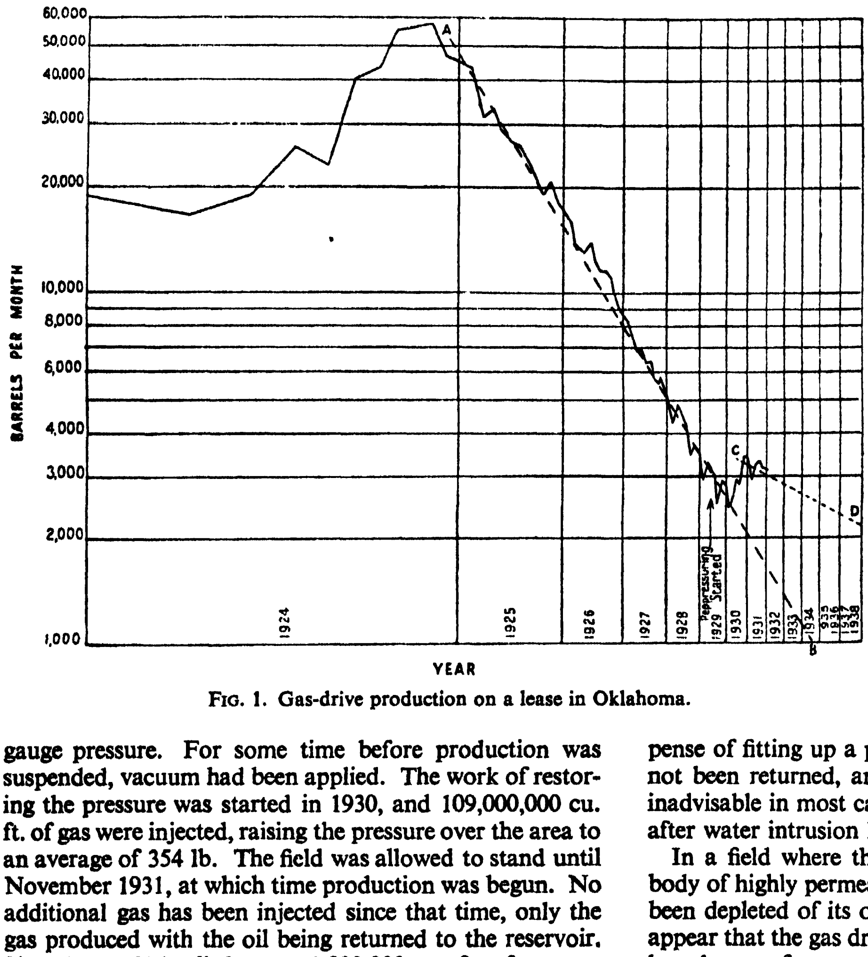

FIG. 1. Gas-drive production on a lease in Oklahoma.

Pressure Drive or Gas Drive

The gas drive has found a wide field of application, although the increase in ultimate recovery by this method does not promise to be as great as was first hoped for.

There do not appear to be any definite ear-marks by which the operator can determine, in advance, the results to be expected from the use of the gas drive. About the only positive method of ascertaining whether it will meet with success is to make a trial. In a good many cases it has been found that after a field has suffered from water encroachment, the expense of fitting up a property for gas-drive operations has not been returned, and it would seem as if it would be inadvisable in most cases to attempt to apply this method after water intrusion had made much headway.

In a field where the reservoir consists of a very thick body of highly permeable sand, and in which the sand has been depleted of its oil to a considerable extent, it would appear that the gas drive would meet with a comparatively low degree of success, owing to the large quantity of gas necessary to fill the sand voids. In such a field there is a pronounced tendency for the injected gas to make its way through the upper part of the sand to the producing wells, without moving the oil along with it.

In fields where the gas drive has been found successful, there has been considerable promise of almost immediately increased production; of extended life for the wells; and of increased ultimate recovery. Fig. 1 is an illustration indicating increased life and increased ultimate recovery resulting from the application of the gas drive, as shown by the production curve on a lease covering 160 acres in a large oilfield in Oklahoma [13, 1933]. The regular production decline on this lease would appear to follow the line *A–B*, and would probably reach the economic limit of about 1,000 bbl. per month during the year 1934. Gas-drive operations were started during the year 1929, and at the end of the year had reached the peak of production on a

gas-drive basis, after which the decline curve would appear to follow the line *C–D*, and by the end of the year 1938 the lease would be capable of producing somewhat more than 2,000 bbl. per month, unless unforeseen difficulties were to arise. It would appear that the immediate production was increased, and also that ultimate recovery will have been increased.

The fields that have responded to the use of the pressure drive with the best results are shallow fields in which the initial pressure was low, thereby resulting in low recovery under ordinary production methods. In such fields there remains a large percentage of the original oil possible to recover since water has not been under sufficient pressure to encroach to a serious extent.

An important consideration in connexion with some gas-drive operations is that of extracting natural gasoline from the recycled gas, especially during periods when the price for natural gasoline is high. Plant outlay for recovering

TABLE IV

State	*Field*	*Bbl. produced per day*	*Range of pressures, lb. per sq. in.*	*M. cu.ft. per day*	*Input gas per bbl. of increased production*
California . .	Brea Canyon	..	590–830	2,100	..
	Buena Vista	..	160–200	125–250	..
	Dominguez	..	440–775	17,450	..
	Elk Hills	..	360–500	135	..
	Seal Beach	..	1,400–1,500	1,600	..
	Shields Canyon	..	230	200	..
Kansas . . .	Eldorado	1,500	..	..	2·667
	„	54	70–150	1,300	2·850
	Miami Co.	..	160–70	..	..
Kentucky . .	Union Dist.	900	..	..	4·800
Louisiana . .	Haynesville	450	..	..	3·800
Ohio . . .	Byers	9	35–120	..	18·800
	Carroll Co.	..	150–300	..	..
	Graham	..	275–300	..	..
	Macksburg	..	45	..	..
	Trail Run	..	46	..	..
Oklahoma . .	Alluwe	..	75–155	..	..
	„	..	35	20	..
	Avant	..	65	..	..
	Burbank	345	55–175	900	4·600
	„	..	20–288	5,085	..
	Cromwell	300	18–240	315	3·000
	Delaware Ext.	..	225–50	..	..
	Healdton	147	..	..	0·650
	Lenapah	165	180	1,048	9·000
	Nowata	60	..	..	3·900
	Ponca City	100	225	230	5·500
Pennsylvania . .	Bingham	..	18	800	..
	Bradford	50	475	617	15·000
	Clarendon	27	..	..	11·900
	Fagundus	80	..	..	3·000
	Hamilton Corners	30	..	..	13·400
	Harmony	9	25	25	3·000
	McKee	..	..	..	6·500
	Knox Plant	42	..	..	3·500
	Poverty Hill	10½	25	80	11·400
	Sheffield	9	..	..	4·700
	Sherard	11·7	..	..	16·800
	Tideoute	..	35	200	..
Texas . . .	Harmel	900	10–45	150	0·520
	Hatchett	..	85–100	52–70	..
	Iowa Park	65	175	350	7·800
	Oldham	475	45–60	90	0·450
	Olney	85	199	975	11·400
	Petrolia	400	85	1,760	0·587
	Red River	1,600	85	1,600	4·000
	Saratoga	..	75–185	17	..
	Turbeville	1,093	..	..	0·700
West Va.. . .	Blemont	100	15	700	11·670
	Boggs	103	..	..	5·180
	Henderson	120	30	450	7·500
	Holliday Cove	..	18	35	..
	Mannington	25	..	..	2·550
	Prunty	61	350	236	4·630
	Richardson	23	..	..	103·000
	St. Mary's	4	15	50	21·700

natural gasoline, however, is appreciably increased over that required for straight gas-drive operations.

Compressed air was employed as a medium for pressure drive in the early days of many fields, particularly during the initial stages of the operations when gas was not available in sufficient quantity. At the present time, gas is probably employed to a greater extent than air, partly because this method supplies gas for fuel uncontaminated with air in driving the gas-engine compressor units.

The choice of wells for use as input points appears to be more a matter of trial, than of arbitrary selection. Geometrical patterns in connexion with input wells would simplify the operations considerably, if such wells were suitable for the purpose. Such patterns would, in many cases, necessitate the selection of good producing wells as input points, which arrangement possesses many objections. The lack of uniformity in the sand has a considerable bearing on the wells that are found to serve as best injection wells.

In several fields, new wells have been drilled especially for the purpose of being employed as input wells. However, during the past three or four years, while oil has been commanding a low price, the expense in connexion with drilling new wells for use as points of gas injection has prevented many such wells being employed.

A gas-drive operation can be laid out with much better chance of success if a large area can be combined under a single experienced management. This is exemplified by the success attending the operation of the Delaware Consolidated Company in the Nowata field, Oklahoma [1, 1932; 5, 1928], and that in the Union District, Eastern Kentucky [2, 1932]. Both of these operations include large productive areas which have been placed under the management of Dunn and Lewis.

The object of any repressuring programme must in practically every instance have in mind the winning of greater profits, attended, if possible, by increased recovery. Consequently it is necessary to investigate the matter of expense required to equip a property for gas-drive operations, to ascertain the operating costs, and to determine the increased revenue that might be expected. If the capital invested does not have a fair chance of being returned with a reasonable increment, it would appear to be advisable to make no change in the methods already in use until some more positive method has been discovered. The gas drive has been quite successful in a large number of instances; it has also been unsuccessful in several projects, and while it may be impossible to determine in advance the degree of success that may be obtained, it is well to study the limitations that surround the proposition.

The part of the investment involving the major portion of the outlay is usually that for the compressor plant. This cost will be based on the necessary pressures and on the quantity of injection gas required, therefore, a study of pressures and of quantity of gas required are preliminary to any such investigation. Table IV gives a range of pressures and quantity of gas employed in various gas-drive operations.

The data in Table IV do not necessarily represent an average over any given period of time, but rather a statement as of some given time when data were available.

It will be observed that the range of input volumes and pressures varies between wide limits. This is often found to be the case, even in instances of leases that are close together, and may be due to the character of the sand, whether water encroachment has taken place, whether vacuum has previously been employed, and in many cases may depend to a considerable extent on the opinions of the various operators as to the quantity of gas that should be injected.

It is probable that most of the low pressures noted in Ohio, Oklahoma, Pennsylvania, and West Virginia are due to a previous use of vacuum. In California the high pressures employed are due to projects bordering on pressure maintenance, and to the use of gas drive in the early life of the field.

Pressures employed in the various states would appear to be approximately as given in Table V.

TABLE V

Range of Pressures Employed in Various States where using Gas Drive

State	*Range of pressures, lb. per sq. in.*	*Approximate average pressure, lb. per sq. in.*
California	160–1,500	500
Kansas	70–170	125
Ohio	35–300	150
Oklahoma	18–400	175
Pennsylvania	– 14*–475	75
Texas	10–1,300	300
West Virginia	–26*–350	25

* This refers to inches of vacuum.

The usual pressures appear to range from 25 lb. to 500 lb. per sq. in. Higher pressures than 500 lb. are seldom employed except for pressure maintenance work. The installation cost of compressors will depend to a considerable extent on the pressure required. For pressures less than 100 lb., single-stage compressors can be employed; for pressures ranging from 100 to 300 or even 400 lb., two-stage compressors will usually be employed; and for pressures in excess of 300 to 400 lb., considerable economy in operating costs can be effected by employing three-stage compressors. When the higher pressures are required, it becomes necessary to employ compressors capable of handling high pressure, and the installation cost is necessarily increased.

The quantity of input gas required per barrel of increased production, as a rule, is not a low figure, although there are examples where low ratios have been obtained.

A general summary of the quantity of input gas used in gas-drive operations in a number of projects in various states [13, 1933] is given in Table VI.

TABLE VI

Cubic Feet of Input Gas per Barrel of Increased Production

State	*Cu. ft. input gas per bbl. of increased production*	
	Range	*approximate average*
Illinois	..	7,400
Kansas	..	2,750
Kentucky	..	4,800
Oklahoma	600–9,000	4,500
Pennsylvania	3,000–15,000	8,300
Texas	450–8,670	4,000
West Virginia	2,550–103,000	8,000

In instances where the cost of compressing the gas is very low, that is, 1 cent or less per 1,000 cu. ft., the costs per barrel of increased production are low in nearly all cases of gas-drive operations, and the operation is usually justified from the economic point of view.

Cost of Plant for Gas-drive Operations

From the data given in Tables V and VI, one may obtain a preliminary idea as to the kind of plant required, from which data the installation cost can be approximated.

For example, we might select a field where there are 100 wells yielding 3 bbl. per well per day, and where by means of gas drive, there is hope for a daily increase of 100%. The total production would then be increased from 300 to 600 bbl. per day. We might assume as a starting-point that the quantity of gas required would be 4,000 cu. ft. per bbl. of increased production, making a total of 4,000 × 300, or 1,200,000 cu. ft. of gas required per day. We may assume that 20 wells would be taken off production and employed as injection wells, leaving 80 wells to furnish the production of 600 bbl. per day. The quantity of gas injected into each input well then averages 60,000 cu. ft. per day, under which condition we may assume that the input pressure would be about 150 lb. at the compressor plant.

A further assumption might be made that before repressuring is started the gas-oil ratio is in the neighbourhood of 300 cu. ft. per bbl., and for 600 bbl. would amount to a total of 180,000 cu. ft. per day. The total output of gas would then amount to 1,200,000 plus 180,000, or 1,380,000 cu. ft. per day, or an average of 17,250 cu. ft. for each of the 80 producing wells, or 2,300 cu. ft. of output gas per barrel of oil produced.

The plant would require a net capacity of 1,200,000 cu. ft. per day, or 833 cu. ft. per minute at 150 lb. discharge pressure. Assuming the volumetric efficiency at 75%, the displacement capacity would be 1,600,000 cu. ft. per day, or 1,100 cu. ft. per minute.

The selection of the type of plant for handling this work would depend on the following considerations:

1. Most economical use of fuel.
2. Extraction of gasoline.
3. Handling of plant by lease attendants.
4. Possible application of gas-lift to some of the wells.

Compressors for gas-drive plants have been erected, using the following types of power drive:

1. Gas engines, direct-driven or belted.
2. Oil engines, direct-driven or belted.
3. Steam engines, direct-driven or belted.
4. Electric motors, belted.

Since most cases of gas-drive operations employ gas, rather than air, for injection into the formation, it is customary at the present time, to employ gas engines for driving these compressors. Either large or small compressor units can be employed for extracting gasoline, although the usage tends toward the large type of compressor, ranging from 165 to 230 h.p., when gasoline extraction is being carried on.

If the plant is to be handled by the usual lease attendants, it is desirable that the compressors and engines be as simple as possible, for which reason the small, two-cycle unit appears to have the preference, and a unit ranging from 50 to 100 h.p. seems to suit the purpose fairly well.

If gas-lift is to be employed on some of the wells, the smaller unit will allow greater flexibility, and make unnecessary the compressing of all the gas to the pressures required at the wells requiring the highest pressures.

For compressing 833 cu. ft. of gas per min. from atmospheric intake to 150 lb. discharge pressure at two-stage compression, would require a total of approximately 180 h.p., for which two 90-h.p. compressor units could be selected. The cost of installing two such units would depend on conditions, locality, &c., and might be in the neighbourhood of $15,000 for new equipment, and as low as $7,500 for used equipment. Assuming that the plant would have a life of 10 years, the depreciation on new equipment would amount to $1,500 per year, or $125 per month. Costs of operation would then be approximately as follows:

	Total cost per month
Depreciation	$125·00
Maintenance, at 5% per annum	62·50
Taxes, at 2% per annum	25·00
Insurance at 1% per annum	12·50
Lubricating oil, 50 gal. at $0.35 per gal.	17·50
Labour, 1 man at $125 per month	135·00
Total, per month	$377·50

The quantity of gas compressed at 1,200,000 cu. ft. per day for 25 operating days per month, would be 30,000,000 cu. ft., and the cost per thousand cu. ft. would be 1·26 cents.

This is a very low cost for compressing gas in a small plant, but is based on the assumption that the plant would be handled with only one attendant, with the assistance of the general lease labour for which no extra expense would be required. Under most conditions the item for labour would be higher than that assumed. This estimate also assumes that gas for fuel without expense would be available on the lease from the gas produced with the oil from the formation.

In addition to the outlay for the plant, there would be a considerable investment for pipelines to convey the compressed gas to the wells and to return the gas to the plant. This outlay would depend on the distances from the plant to the wells. For furnishing input gas to 20 wells, and for returning gas from the 80 wells to the plant, it is probable that an expenditure of about $10,000 would be required on which depreciation and other fixed charges would be about $100 per month.

The total operating expense, including depreciation, would then be approximately $477·50 per month. The increased production based on 300 bbl. increase per day for 25 days per month would be 7,500 bbl., which at $1·00 per bbl. would yield a revenue of perhaps $4,000 to $5,000 per month after allowing for royalty, and deducting expense for compressor operation, gross production tax, and extra lease expense for treatment and handling the oil.

It is not to be expected that this is typical of the outcome in gas-drive operations, since many questions often enter into the matter which are quite different from the assumptions made in the foregoing example. It is, however, illustrative of the manner in which the problem of costs can be approached and estimated in a fairly simple manner.

Compression costs, including depreciation of compressor plant equipment, extra pipelines, control valves, meters, &c., are seldom as low as 1·26 cents per thousand cu. ft. In a large plant, costs could be assumed at some figure between 2 cents and 3 cents per thousand cu. ft., and even in a small plant, where no extra labour is required other than the regular lease force, the costs might be as low as 3 cents per 1,000 cu. ft. [12, 1933]. Compression costs have been found to be as high as 5 to 10 cents per 1,000 cu. ft. in several instances where proper study was not given to the conditions involved, and the operator would do well to make a careful survey of his conditions to ascertain what he might expect in the way of costs before investing any considerable capital in such an undertaking. For instance, if the input gas were to approach 8,000 cu. ft. per bbl. of increased production, and the cost of compression were

10 cents per thousand cu. ft. at the present price for crude oil in the Mid-Continent or in California, there would be little chance of showing a profit. On the other hand, such conditions might not be prohibitive in the Eastern States if it appeared that the price of oil would be $1·50 or better, and if the quantity of gas required were not too great.

In connexion with repressuring, very little attention has been given to the study of lifting the oil under natural flow with the combined gas associated with the oil and that coming from the gas drive. The quantity of gas used, such as that mentioned in Tables V and VI, would imply the possibility of flowing the oil naturally if arrangements were made with the proper sizes of tubing, automatic intermitting devices, &c. If this were worked out in a satisfactory manner, it would seem as if the use of gas drive both for driving the oil to the well, and for lifting it to the surface, might make for considerable economies in the lifting of oil.

Future recovery of oil, as of the time when gas-drive operations are started, may be considerably greater than would be the case without the drive. Based on the total ultimate recovery, however, the percentage of increase by reason of using gas drive may not appear great, inasmuch as so large a percentage of the ultimate recovery has already been obtained during the flush stage.

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PRODUCING OIL WITH GAS-LIFT

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THE first use of the air-lift for elevating a liquid is supposed to have been discovered by Loscher in 1797. The Pohle air-lift was installed about 40 years ago in various waterworks for elevating water, and was among the first practical applications on a commercial scale.

Application for patent was made, in 1864, for lifting oil by air-lift in the Oil City field, Pennsylvania, but little progress appears to have been made at that time. Commercial application of the air-lift, for extracting oil, was made in the Baku field in 1900, and, somewhat later, it was employed in the Gulf Coast area in the United States.

Studies of the principles involved in gas-lifting oil were started in Oklahoma [7, 1927], and in California [10] about the year 1925–6, and these studies have continued up to the present time. Perhaps the favourable development taking place in the Seminole area, Oklahoma, in 1927–8 [16], provided the stimulus for carrying forward the gas-lift method to a point beyond that of any previous period. The development at Seminole was followed by extensive operations in the Oklahoma City field [2, 1934], where conditions have been found to be favourable for the use of this method of lifting oil.

Theory of the Gas-lift.

The gas-lift operates by means of energy, made available through the expansion of gas under pressure, when ascending from the lower end of a pipe to the upper end, the gas in its upward movement carrying liquid entrained with it. Gas, in expanding, can be made to perform useful work, the measure of which is determined by the number of foot-pounds developed during its expansion. A perfect gas in expanding isothermally, performs work according to the following formula:

$$W = P_2 V_2 \log_e \frac{P_1}{P_2} \tag{1}$$

where:

$W =$ the work done in ft.-lb.
$P_1 =$ the higher pressure in lb. per sq. ft. abs.
$P_2 =$ the lower pressure in lb. per sq. ft. abs.
$V_2 =$ the volume of gas in cu. ft. at pressure P_2.
$\log_e$ refers to logarithms with Napierian base.

Formula (1) can be simplified for general use by making the following assumptions:

$P_2 =$ pressure at sea-level, that is, 14·7 lb. per sq. in.
$V_2 =$ the unit volume of gas, that is, 1 cu. ft. at sea-level pressure.
Pressures, based on lb. per sq. in.
Logarithms, changed to the Briggs, or common, system.

Introducing these values in Formula (1) we have:

$$W = 144 \times 14{\cdot}7 \times 1 \times (2{\cdot}302585 \log_{10}) \frac{P_1}{14{\cdot}7}$$
$$= 4{,}874 \log \frac{P_1}{14{\cdot}7}. \tag{2}$$

The work performed in lifting one barrel of liquid of 42 U.S. gal., having a specific gravity of 1, a given distance is:

$$W_1 = 350 \times L, \tag{3}$$

where

$W_1 =$ the number of ft.-lb. required.
$350 =$ the approximate weight in lb. of 1 bbl. of liquid having specific gravity of 1.
$L =$ the number of feet that the liquid is lifted.

The quantity of gas, Q, required to lift 1 bbl. of this liquid to a given height is then as follows:

$$Q = \frac{350 \times L}{4{,}874 \log \frac{P_1}{14{\cdot}7}} = \frac{L}{13{\cdot}926 \log \frac{P_1}{14{\cdot}7}}. \tag{4}$$

For conditions where P_2 is other than 14·7, and for a liquid whose specific gravity is other than 1 (thereby changing the factor 350), the appropriate factors must be substituted for those employed in the formula.

Formula (4) considers the lifting to be done at an efficiency of 100% which is, of course, never the case. In order to determine the actual quantity of gas required, a factor for efficiency, E, must be introduced into the denominator, whereby formula (4) becomes:

$$Q = \frac{L}{E \times 13{\cdot}926 \log \frac{P_1}{14{\cdot}7}}. \tag{5}$$

If isothermal expansion be assumed as a basis, it has been observed that, as an average, the factor, E, corresponds approximately to the percentage of submergence [20] in instances where the percentage ranges from 10 to 30%, and for oils that vary in specific gravity between 0·75 to 0·85.

An example will clearly illustrate the application of formula (5), for which purpose the following assumptions are made:

Total length of eductor, 4,500 ft.
Pressure, P_1, at bottom of the eductor is 300 lb. per sq. in. gauge pressure, or 314·7 lb. absolute.
Pressure P_2, is 14·7 lb. absolute, or sea-level pressure.
Specific gravity of the oil is 0·80.

Under the assumed conditions, P_1, or 300 lb., is equivalent to a submergence of:

300×2·304, or 691 ft. of water, or 691/0·8, or 864 ft. of oil, and the percentage of submergence is $\frac{864}{4{,}500}$, or 19·0%.

The lift, L, is (4,500–864) or 3,636 ft.

Substituting the above figures in formula (5) we have:

$$Q = \frac{0{\cdot}8 \times 3{,}636}{0{\cdot}192 \times 13{,}926 \log \frac{314{\cdot}7}{14{\cdot}7}} = 818 \text{ cu. ft. of gas.} \tag{6}$$

The quantity of gas is, therefore, 818 cu. ft. required to lift 1 bbl. of oil of a specific gravity of 0·80, through a pipe, 4,500 ft. in length, where the gas is admitted to the bottom of the eductor column at a gauge pressure of 300 lb. per sq. in.

The efficiency factor, E, gradually increases as the percentage of submergence declines below 10%, and it decreases as the percentage of submergence increases above

65%, although insufficient data are available to determine the exact relationship that exists.

Expansion of gas does not take place isothermally when lifting a liquid, although the expansion closely approaches the isothermal type when the quantity lifted is large. This observation was made by the writer when lifting large quantities of water in a mine where the water-level was accessible and where it was convenient to observe the temperature of the water in the reservoir, and at the discharge from the eductor column [14, 1920]. When very small quantities of liquid are lifted from great depths, exponential expansion takes place, but data are very difficult to obtain, covering this type of expansion. However, the factor, E, in formula (5) has been determined from a very large number of tests, based on isothermal expansion calculations; therefore, the results determined by the formula will not be seriously affected if exponential expansion be considered, provided a corresponding change is made in the factor E.

It was stated previously that the average efficiency obtainable corresponds to the percentage of submergence, but this should be amplified by stating that the factor E will vary with the diameter of the pipe, the temperature, and the viscosity of the liquid, and with the method of lifting, depending on whether the liquid is to be lifted through unobstructed pipe with smooth surface, or whether it is to be through the annular space. Flow through the annular space may be considerably less efficient than through a pipe of equivalent cross-section.

Factors so far recognized as having an influence on gas-lift flow are as follows:

1. Pipe. Length and diameter.
2. Pressure. At entrance and at discharge of the eductor column.
3. Liquid. Rate of flow, density, temperature, and viscosity.
4. Gas. Density, temperature, rate of flow, and, perhaps, viscosity.

It has been observed that the lifting efficiency increases as the pipe diameter increases, assuming that other factors remain unchanged. For a given rate of flow, there is a diameter that suits the conditions better than any other diameter.

As the length of pipe increases, the capacity of the eductor is reduced, as will be observed in Fig. 1, where a comparison is made between 4,000 ft. of 3-in. pipe and 6,300 ft. of 3-in. pipe.

The pressure condition at the entrance to the eductor has a marked influence on the capacity of the pipe and on the lifting efficiency. Fig. 2 illustrates the quantity of oil that can be lifted through a pipe of a given diameter, at maximum capacity, in the Seminole field, Oklahoma [21]. For example, the capacity of 4,000 ft. of 3-in. pipe at 100 lb. pressure is 140 bbl. of oil per day, whereas the capacity is 1,300 bbl. per day when lifting through 4,000 ft. of annular space between 8¼-in. casing and 4-in. tubing.

General Gas-lift Practice.

There are three general forms of gas-lift flow:

1. Continuous flow.
2. Periodic flow.
3. Intermittent flow.

Continuous flow may be performed through either the casing or the tubing, depending on the conditions existing and on the results to be achieved. If a high rate of flow is desired, particularly in deep wells, it is usual to flow through the annular space, between the tubing and the casing, even though this is at the expense of lifting efficiency. If a low rate of flow be desired, the flow can be carried out through the tubing, although the flow through small tubing will be less efficient than through large tubing (Fig. 3).

Flow through tubing is performed through 2-in., 2½-in., 3-in., 4-in., and sometimes 5$\frac{3}{16}$-in. pipe. Flow through the annular space in practice is through 3-in. with 1-in. to 1½-in. tubing, in which case the production is usually very small; through 4-in. with tubing of 1½-in. to 2-in.; through 5$\frac{3}{16}$-in. with tubing of 2-in. to 2½-in.; through 6⅝-in. O.D. with tubing of 2-in. or 2½-in.; through 7-in. with tubing of 2-in. to 3-in.; and through larger sizes of casing with tubing of 2½-in. to 4-in.

Periodic type of flow is performed through the tubing or through the annular space, with approximately the same sizes of casing and tubing as for continuous flow. This form of flow is usually employed where wells are restricted in production, and where it is convenient to flow the well for a short period each day and then to shut in the well, after which it may remain closed in overnight, or possibly over several days. This method is usually employed where the wells are capable of a large production and, therefore, where fluid levels are high. In starting such wells on gas-lift, especially when they are flowed through the tubing, very high bottom-hole pressures are sometimes encountered and it becomes advisable to employ means of admitting the gas to points in the tubing above the bottom, corresponding to the pressures that the compressors are capable of handling. It is desirable, when the well has been flowed down to this point of gas admission, that a means be provided for closing off the gas from this point in the tubing and allowing it to enter at a lower point in the tubing, which process is continued until the gas reaches the lower end of the tubing. For this purpose it is convenient to employ 'starting' valves, 'kick-off' valves, or 'flow' valves [18, 1934].

Periodic flow is sometimes less efficient than continuous flow or intermittent flow, in that a considerable quantity of gas is wasted at the beginning and end of each period. If, however, the periods are of sufficient duration, this waste may be only a small percentage of the total quantity of gas consumed in lifting the oil.

Intermittent flow is employed in four different types:

(*a*) Through the casing, without chamber at the bottom.
(*b*) Through the casing, with packer and valve, or with packer, chamber and valve, at the bottom.
(*c*) Through the tubing, without chamber, either with plain tubing, or with the Hughes plunger lift type.
(*d*) Through the tubing, with bottom-hole chamber.

Type (*a*) of intermittent flow is employed after the production on continuous flow has declined to a point where production as great or greater can be obtained by intermitting, and where a reduction in the input gas per barrel can be obtained. This type of intermittent flow has been employed in wells 4,000 ft. in depth, making 500 bbl. or less per day; also in wells 6,500 ft. in depth where the production is 1,000 bbl. or less per day. The reduction in input gas when using this type of flow amounts to from 25 to 75% of that required when employing continuous flow.

Type (*b*) of intermittent flow is being employed in a field having depths of 6,500 ft. where the pressure has declined from 2,600 lb. to 200 lb., and where the sand is very porous

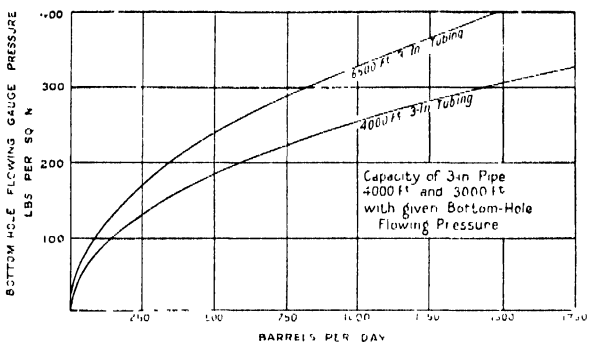

FIG 1

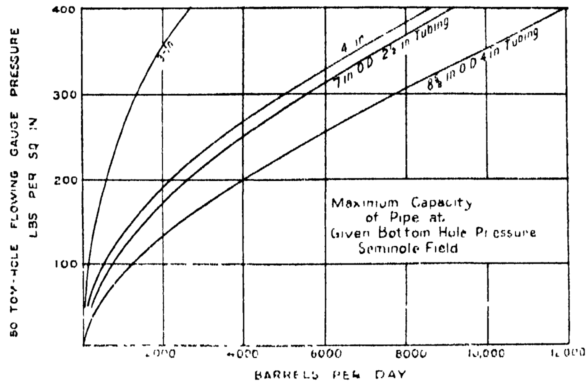

FIG. 2

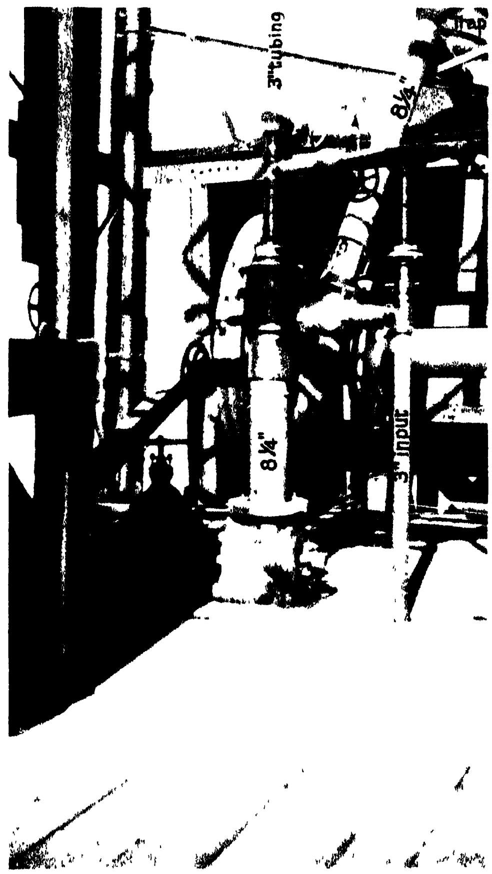

FIG. 3. An efficient well hook-up in the Seminole field, Okla

Fig. 4. National intermitter at Seminole, Okla

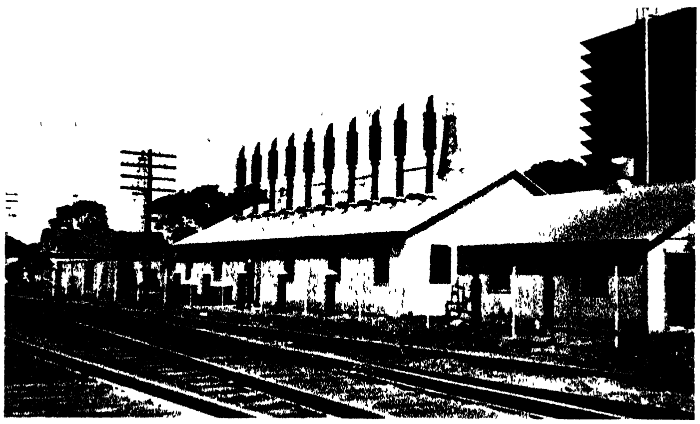

Fig. 5. Compressor plant, Oklahoma City, Okla

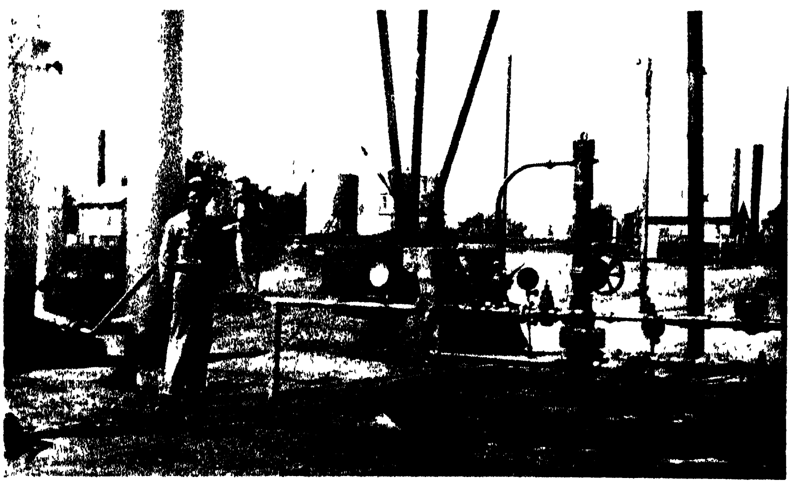

Fig. 7. Hughes plunger lift, Oklahoma City field, Okla

and allows the oil to be partly driven back into the formation, when gas is admitted for lifting the oil, where no check-valve is employed. The reduction in consumption of input gas with this type of flow has been upwards of 50% from that required for continuous flow, in comparatively small wells, that is, wells producing under 500 bbl. per day.

Type (*c*) of intermittent flow has not, as a rule, been successful except with the Hughes plunger lift. This results from the fact that gas admitted to the annular space, in considerable quantity, tends to fill the tubing with oil to the point where the pressure becomes such that the gas is forced back into the sand, before it begins to lift the oil through the tubing. The Hughes plunger lift type of flow has been quite successful in various fields of the United States where the production has declined to a point that is within the capacity of the plunger lift.

Type (*d*) of intermittent flow is employed in wells of 400 to 4,000 ft. in depth. In this method, an outer string of tubing is suspended in the well, at the lower end of which is attached a chamber that occupies most of the space within the casing or liner. The chamber is provided with a standing valve at the lower end. Suspended within the outer string of tubing there is a string of tubing of smaller diameter, through which the oil is forced to the surface. Gas is admitted intermittently to the annular space between the tubing strings, thus closing the standing valve at the bottom of the chamber and displacing the oil into the inner string of tubing through which it is lifted to the surface by the gas flowing through the annular space and pushing the oil up through the inner tubing [13, 1930].

The consumption of input gas in type (*d*) of intermittent flow, is reduced by 25 to 50% of that required for continuous flow, when the daily rate of production is small.

Intermittent Devices. Various forms of automatic devices are employed for admitting gas intermittently to the well. In the Oklahoma City field several intermitters are employed for actuating the flow in types (*a*) and (*b*). The best known of these intermitters in this field are those of Fisher-Foxboro, Foxboro, Hanlon-Waters, and Shipman manufacture.

For intermittently admitting gas to the well, in type (*d*), several makes of intermitters have been employed such as the Jat, Maxiflo, and National Tank Company. The Jat and National Tank Company intermitters are particularly adapted to controlling several wells from a central point. The Fisher-Foxboro, Foxboro, Hanlon-Waters, Maxiflo, and Shipman intermitters are employed for controlling the flow of individual wells (Fig. 4).

Compressor Installations. Compressor Installations are an important part of any gas-lifting operation, comprising the largest part of the expenditures, in connexion with this method of lifting oil (Fig. 5). Various types of compressor plants are employed, which may be classified as follows:

1. Large, centrally located plants, with compressor units of large capacity.
2. Small plants, built on individual leases, equipped with either small or large compressor units, although usually the small units prevail.

From the mechanical point of view, the large centrally located plant would seem to have the preference inasmuch as the cost per horse-power installed, or per unit volume compressed, is less than for small plants. These plants are often built to serve the twofold purpose of extracting natural gasoline, as well as for handling gas-lift operations.

The compressors in large plants are usually direct-driven gas-engine compressors, ranging from 80 to 400 h.p., with preference given to the sizes ranging from 165 to 230 h.p.

The small compressor plants are usually built for handling gas-lift operations in wells on a single lease, or on two or more contiguous leases. When first erected these small plants are usually operated at full capacity and a special force is employed for handling the plants, but after the wells have declined measurably the plant is often handled by the regular lease attendants.

The compressors employed in small plants are of a more diversified character than those employed in large plants, since it is frequently the case that used compressors from other oilfields are moved in and erected. The types of compressors that have been more generally employed in small plants are as follows:

1. Duplex or tandem type, with capacity ranging from 250,000 to 500,000 cu. ft. displacement per day, belt-driven from electric motors or from gas engines.
2. Duplex type, with capacity ranging from 250,000 to 500,000 cu. ft. displacement per day, direct-driven from gas engines.
3. Duplex type, with capacity ranging from 500,000 to 1,250,000 cu. ft. displacement per day, direct-driven from gas engines.

For operations where the life of the plant is certain to be upwards of 5 years or more, where the plant will be operated at close to the rated capacity throughout its life, and where natural gasoline is to be extracted, the large plant with large compressors is preferable because of lower installation and operating costs.

When the plant is to be employed only for gas-lifting, where the life of the operation is uncertain, and where the utmost flexibility is desired, the small plant has often been found more satisfactory than the large plant. In the later life of the operation, the operating costs of a small plant are often much lower than those of a large plant, inasmuch as the regular lease attendants can handle the plant operations, as well as the other lease duties. The operation of a large plant, when the oil has declined to only a small quantity, is often prohibitive in cost.

The installation costs of several compressor plants for handling operations in three of the principal Mid-Continent fields are given in Tables I, II, and III [22, 1934].

TABLE I

Cost of Various Compressor Plants in the Seminole Field, 1927–30

Kind of plant	*Cu. ft. displacement per day*	*Approximate cost*	*Bbl. per day*	*Cost per bbl. of daily production*
		$		$
Semi-portable compressor equipment (1)	2,000,000	26,000	3,000	6·70
Semi-portable equipment (2)	4,000,000	46,000	6,000	7·70
Semi-portable compressor equipment	6,000,000	55,000	9,000	6·20
Small units, permanent equipment (3)	3,600,000	80,000	5,000	16 00
Large units, permanent equipment (4)	10,000,000	200,000	15,000	13·30
„ „ „ (5)	1,700,000	25,000	2,500	10·00

(1) Small units, driven by electric motors, timber foundations, new equipment.
(2) Small units, driven by electric motors, timber foundations, used equipment.
(3) Small 90-h.p. units, gas engines, concrete foundations, new equipment.
(4) 165-h.p. units, gas engines, concrete foundations, new equipment.
(5) 165-h.p. units, gas engines, concrete foundations, used equipment.

TABLE II

Cost of Various Compressor Plants in the Oklahoma City Field, 1933–4

Kind of plant	*Cu. ft. displacement per day*	*Approximate cost*	*Bbl. per day*	*Cost per bbl. of daily production*
		$		$
Semi-portable compressor equipment (6)	2,000,000	12,000	2,500	5·00
Small units, permanent equipment (7)	2,700,000	41,000	3,000	13·70
Small units, permanent equipment (8)	2,700,000	23,000	3,000	7·70
Large units, permanent equipment (9)	2,000,000	32,500	2,500	13 00
Large units, permanent equipment (10)	2,550,000	18,000	3,000	6·00
Large units, permanent equipment (11)	6,700,000	83,000	8,000	10·40

(6) Small units, electric-motor driven, timber foundations, used equipment.
(7) 90-h.p. units, direct-driven gas engines, concrete foundations, new equipment.
(8) 90-h.p. units, direct-driven gas engines, concrete foundations, used equipment.
(9) 100-h.p. units, direct-driven gas engines, concrete foundations, new equipment.
(10) 200-h.p. units, direct-driven by gas engines, concrete foundations, used equipment.
(11) 230-h.p. units, direct-driven gas engines, concrete foundations, new equipment.

TABLE III

Cost of Various Compressor Plants in the East Texas Field, 1924

Kind of plant	*Cu. ft. displacement per day*	*Approximate cost*	*Bbl. per day*	*Cost per bbl. daily production*
		$		$
Semi-portable compressor equipment (12)	400,000	2,500	500*	5·00
			250†	10·00
Permanent compressor equipment (13)	600,000	8,500	700*	12·15
			350†	24·30
Permanent compressor equipment (14)	500,000	4,500	600*	7·50
			300†	15·00

(12) Small units, driven by electric motor, used equipment.
(13) 90-h.p. units, driven by gas engines, concrete foundation, new equipment.
(14) 90-h.p. units, driven by gas engines, concrete foundations, used equipment.
* This reference is to the probable production that could be made by these plants if the wells were opened to the capacity of the plant.
† This reference is to the actual production being made at restricted rate of production.

Gas-lift Practice in Various Countries.

The gas-lift has been, and is being, employed in nearly all the countries where oil is being produced. These countries include the Argentine, Colombia, Dutch East Indies, Germany, Mexico, Peru, Poland, Roumania, Russia, Trinidad, United States, and Venezuela.

In the Argentine, the gas-lift has been employed in the Plaza Huincul and Salta fields. Continuous and intermittent flow are employed. Continuous flow is usually through tubing, inasmuch as the wells are relatively shallow and production is not large. When wells have declined to a comparatively small production, the Maxiflo intermitter has been employed to advantage.

The gas-lift has been employed in Colombia to a considerable extent, although it has been somewhat curtailed of late, due to trials being made with pressure-maintenance operations. Continuous flow has been employed, both through the tubing and through the annular space.

Some trials have been made in the Dutch East Indies, both with continuous flow and intermittent flow, but details are not available.

In the Edesse field, Germany, the periodic method of gas-lift has been employed to handle the small production that is being made. Intermittent flow has also been employed to a small extent.

The gas-lift has not been employed in Mexico to any considerable extent, due to intrusion of salt water, and to the fact that the oil is very heavy and viscous, although several efforts have been made to employ this method.

Gas-lift operations have been employed to a considerable extent in Peru, in La Brea-Parinas field. The flow for the most part has been continuous, both through the tubing and casing, depending on conditions and on the quantity that it is desired to produce. Tapered tubing has been employed to a considerable extent in this field. A novel use of double concentric strings of tapered tubing has been made here, in order to avoid the necessity of using high pressure, when starting wells flowing through the tubing. Intermittent flow has also been employed in Peru, mostly with intermitters designed locally by those in charge of operations.

Small operations in intermittent gas-lift flow have been carried out in Poland, although the efforts have been confined to a small area, not far from the Boryslaw field.

Available records indicate that the application of the gas-lift in the Baku field, Russia, in 1900–4, was, perhaps, the first operation of any magnitude in the lifting of oil by this method [23, 1920; 24, 1925]. Reports indicate that at the present time this method is again being employed to a considerable extent and at the time of the last available report, the quantity so produced was between 20 and 25% of the total production.

Air-lift operations have been conducted in Trinidad for some years. Intermittent flow is being practised, using the Maxiflo, Jat, and similar methods [11].

By far the widest application of the gas-lift has taken place in the United States. The states where this method has been employed include Arkansas, California, Kansas, Louisiana, Oklahoma, Pennsylvania, Texas, and, perhaps, several other states where smaller operations have been under way.

At the present time the more notable work is being done in California [9, 1932], Oklahoma [3, 1934], and Texas [17, 1933], and reference will be made to some fields in these three states.

California. In California there are various fields in which wells have reached a depth where it is not at all unusual to bring in production initially with gas-lift. These fields include Coyote, Dominguez, Huntington Beach, Long Beach, Mountain View, Playa del Rey, Santa Barbara, Santa Fé Springs, Seal Beach, and Ventura Avenue.

In the Santa Fé Springs field, the Union Oil Co. has installed an elaborate system of separators and compressor arrangements [1, 1934] by which the gas from wells produced under high back pressure can be employed directly for flowing lower-pressure wells, or can be admitted to the intake of a compressor for boosting to a higher pressure, depending on the requirements of the system.

The Jat method of intermittent flow has been used to a considerable extent in various California fields and favourable results are being obtained.

Oklahoma. Various fields in Oklahoma have proved favourable for the application of the gas-lift, especially those in which the Wilcox sand is developed. The Wilcox sand is relatively thick, porous, quite permeable, and fairly

well consolidated, consequently the flow of oil and gas from this sand into the wells is of a character that permits very large production to be made without offering any serious difficulties. The first field of this character where large production was made by gas-lift was at Tonkawa [15, 1926]. Another field of consequence in the Wilcox sand, where the gas-lift was applied, was Seminole, where upwards of 250,000,000 bbl. of oil were extracted by this method. Some of the wells in this field are yet operated by this method, even though they have reached an age of seven years.

The method that has been employed in the Seminole field is largely that of continuous flow, and the oil is lifted usually through the annular space between casing of 7-in. O.D., and

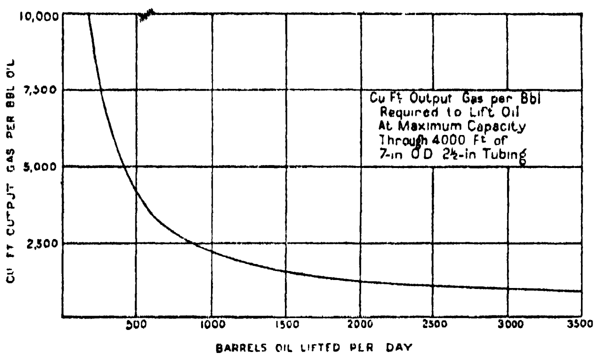

FIG. 6.

tubing of 2½-in. (Fig. 6). Most of the wells now on gas-lift in this field are operated in this manner. This method was employed owing to the requirements of lifting the oil at the maximum daily rate. Later, when the production had declined to a small daily rate, it was sometimes found more economical to run 4-in. tubing and produce the wells through the tubing. After wells had declined to a smaller production than was feasible to produce through the 4-in. tubing, intermittent flow was employed of type (*d*) to a considerable extent, and in some cases type (*a*) of intermittent flow was employed, especially where the oil was accompanied by a large percentage of water. Tapered tubing was also employed in a large number of wells in the Seminole field and input gas factors were much reduced, but it was found, after a time, that corrosion reduced the cross-sectional area in the lowermost part of the tubing which reduced the production by a prohibitive amount.

At the present time the gas-lift is employed probably more extensively in the Oklahoma City field than in any other field in the world. In this field the quantity of oil produced by this method ranges from 50,000 to 100,000 bbl. per day. The wells are in the neighbourhood of 6,500 ft. in depth, and up to the present time no other practicable method has been devised that can lift the oil, at this depth, in large quantity. Some wells that were completed for an initial production of 25,000 to 100,000 bbl. per day, are yet capable of yielding from 5,000 to 10,000 bbl. on gas-lift, particularly where the wells were completed with casing of 9-in. diameter or larger [19, 1934].

The practice in the Oklahoma City field is to flow the wells through casing of 6⅝-in. or 7-in. O.D. in which is suspended tubing of 2-in. or 2½-in. diameter. The larger sizes of casing, that is, 9-in. or 9⅝-in. O.D. are provided with tubing of 2½-in. or 3-in., and it would be better if the tubing in these large casings were of 4-in. diameter.

In the early days of the Oklahoma City field when the starting-pressures were high, starting valves were employed quite extensively, the P. and T. valve being the most popular.

An interesting comparison of input gas factors required in the Oklahoma City field for producing wells through different sizes of pipe is given in Table IV.

TABLE IV

Quantity of Input Gas required to Lift One Barrel of Oil in the Oklahoma City Field through Different Sizes of Pipe

How flowed	*Bbl. oil per day*	*Cu. ft. input gas per bbl. of oil*
Through 2½-in. tubing	565	1,390
Through space between 9-in. casing and 2½-in. tubing	6,865	570
Through 3-in. tubing	888	1,095
Through space between 9-in. casing and 3-in. tubing	5,928	597

The data in Table IV bring out the advisability of lifting oil through pipe of large diameter [19, 1934], provided there is a large quantity of oil that can be lifted, and also provided that conditions are such that the oil lifted in this large quantity can be absorbed by the market.

The type of flow employed in the Oklahoma City field has been usually of the continuous method, flowing through the annular space in most cases, although in some cases through the tubing. Recently, the production in many wells has declined to the point where the quantity of input gas per barrel on continuous flow is excessive, being from 4,000 to 10,000 cu. ft. per bbl., and recourse has been had to intermittent flow of types (*a*), (*b*), and (*c*), by which methods the input gas factors are reduced to between 25 and 50% of the quantity required on continuous flow. The Beardmore, Clark, and Hewgley makes of flow devices, are employed for type (*b*), and the Hughes plunger lift for type (*c*). Some 70 wells are reported to have been equipped with the Clark flow device, or 'bottom-hole intermitter', and 75 or more wells have been equipped with the Hughes plunger lift, in the Oklahoma City field [4, 1932] (Fig. 7).

In the Hughes plunger lift, the interior of the tubing is reamed to a smooth surface and uniform diameter, and a small, close-fitting, hollow, metal cylinder, provided with a valve, travels the full distance of the tubing, carrying a load of oil to the top on each trip. This method is being employed with tubing diameters of 2½-in., 3-in., and 4-in. in this field, and lifting at rates up to 300 bbl. per day in some instances at an expenditure of less than 25% of the quantity of input gas that is required when using continuous flow, for wells having the same capacity. When employing the 4-in. tubing, it would appear that the point at which to begin using this method is about 300 bbl. per day; with 3-in. tubing, the practicable capacity is about 200 bbl. per day; and with 2½-in. tubing the capacity is up to 125 bbl. per day. In one well equipped with 2½-in. tubing, with bottom-hole flowing pressure of about 30 lb., the capacity was about 20 to 25 bbl. per day, with consumption of approximately 1,200 cu. ft. of input gas per bbl. of oil lifted, from a well 6,500 ft. in depth. The plunger lift is employed in wells of much shallower depth, but the advantage over the pump is not so marked in that the older methods can lift the oil from shallow depths, whereas in deep fields the plunger lift for wells of small capacity is much superior to the older pumping methods heretofore in use.

Texas. Various fields have been produced in Texas by

air- and gas-lift. The first known application of air-lift was in the Corsicana field, in 1899, where periodic flow was employed. The air-lift has been employed at Church Fields, East Texas, Goose Creek, Government Wells, Hendrick, Hull, Humble, Luling, Miranda City, Orange, Pierce Junction, Powell, Raccoon Bend, South Liberty, Spindletop, Sugarland, Wortham, and other fields in Texas.

The principal field in Texas in which the air-gas lift is now being employed is that of East Texas [5, 1934], where exceptional conditions exist in connexion with the use of this method. The wells are capable of producing several thousand bbl. per day, and yet are restricted to between 20 and 35 bbl. per day. Bottom-hole pressures are high since the reservoir pressure is in the neighbourhood of 1,200 lb. per sq. in. The gas/oil ratio is approximately 370 cu. ft. per bbl., and the gas does not begin to dissociate from the oil until the pressure has been reduced to about 750 lb. [8, 1933]. It is necessary to open the wells each day, and flow them for a short period and then close them in. In the early days of the field there was little difficulty in starting the wells under natural flow, but during the past year there has been an increasing number of wells that will not start to flow, when opened up, due to decline in pressure; to intrusion of water; and to insufficient gas collecting to start the wells.

In order to produce each day the small quantity of oil allotted to the well, it is desirable to lift the oil through the tubing. The difficulty in starting wells through the tubing, however, is increasing, consequently it has been found necessary to install small air-lift plants for handling this work.

Casings employed in the East Texas field are usually 6⅝ to 7-in. O.D., although many smaller casing sizes are employed. Tubing diameters, in this field, are usually 2-in. or 2½-in. In order to start the wells flowing through the tubing, the practice has been developed of inserting in the tubing string a series of 'starting' valves [18, 1933], about 8 in number, the uppermost being inserted in the tubing collar at a point approximately at the static level of the oil. Compressed air or gas is admitted to the casing, and the wells are started by means of these valves, and the flow continued as long as required [12, 1934]. The better known makes of starting devices employed in the East Texas field are the Bryan, P. and T., and Western Pneumatic valves. In some cases the wells will continue to flow naturally after they are once started. The number of plants for handling the production by means of this method is gradually increasing.

The compressor plants employed in the East Texas field on individual leases consist of a single unit, having capacity of 250,000 to 500,000 cu. ft. displacement per day, and can be installed for a cost ranging from \$2,500 to \$8,500, and will service ten or more wells at the present rate of production. (See Table III for costs of installing plants.) The starting-valve equipment will cost about \$400 per well, making an equipment cost that ranges from \$650 to \$1,250 per well.

Venezuela. Gas-lifting oil in Venezuela has been on a rather large scale. In October 1934, the number of wells on gas-lift was as follows [6, 1934]:

Field	*Number of wells on gas-lift*	*Total number of producing wells*
Lagunillas	121	971
La Rosa	87	382
Mene Grande	97	135
El Mene-Media	47	93
La Paz-Concepcion	4	81
	356	1,662

General Observations

The gas-lift has not been employed to any extent for lifting the oil in shallow wells, although there is no reason why this method cannot be employed, except for the general lack of knowledge of handling the operation in an economical manner. Shallow wells are usually small producers, and heretofore it has not seemed advisable to employ engineering assistance for handling this class of production. Moreover, shallow fields already developed have been provided with lifting equipment, and financial considerations do not warrant changes, involving any capital expenditures in such fields.

If new fields of the shallow type are discovered, it would be quite feasible to employ the gas-lift for handling the lifting operations. This could be done in a way to fit in naturally with repressuring, or with gas-drive operations.

In the deep fields, where daily production is large and where the pump works at a great disadvantage, both as to capacity and cost, the gas-lift is very largely depended upon to handle the production, after natural flow ceases. In many cases it has been found that the gas-lift can be applied before natural flow ceases for the purpose of increasing production and reducing the gas-oil ratio.

New applications and devices are constantly being worked out for increasing the scope of the gas-lift process, and there are many reasons for believing that the not-distant future will see greater improvements than have already been made in this method of lifting oil.

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OIL-WELL PUMPING

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In recent years much has been said concerning the various aspects of oil-well pumping and the new devices and operations made necessary in view of the increasing problems incident to the production of deep wells. Although repetition of generally accepted principles is necessary, it is intended that the ensuing discussion will emphasize the more practical phases of current pumping practice. Many details readily available in the literature will, therefore, be omitted.

In general, oil-well pumping is accomplished to-day in various manners:

1. The usual submerged plunger pump.
2. Submerged centrifugal pumps driven by directly connected electric motors.
3. Hydraulic reciprocating displacement pumps.
4. Rotary positive displacement pumps.
5. Various combination pumping and flowing devices more properly grouped under air-gas lift methods.

The operating principles of the submerged oil-well plunger pump have been described by Uren [19, 1928] and others. Essentially the pump is of the displacement type, and consists of a reciprocating plunger and travelling valve operating with small clearance within a stationary tube or working barrel. The latter is provided at its lower end with a standing valve. In the older common types of pumps the working barrel is submerged in the well fluid and attached to tubing extending to the surface. The travelling valve is actuated by means of reciprocating motion induced by surface equipment, and transmitted through the tubing by means of a sucker-rod string. During recent years various types of insert pumps have been used successfully. The operating principle of insert pumps is similar to that of common types. However, instead of screwing on to the tubing, anchoring is effected by means of special seating attachments engaging suitable shoes on the bottom part of the tubing string. A principal advantage of the insert pump is the ease of removal by means of sucker rods in lieu of laborious tubing pulling incidental to the removal of the common type pump. The submerged positive displacement plunger pump has proved the most practical and economical means of pumping the majority of oil-wells. Consequently, the greater part of this article will deal with principles of design and operation of plunger pumps and associated subsurface and surface equipment.

The submerged electrical centrifugal pump [3, 1930] consists of a submerged motor directly connected to a centrifugal pump near the well bottom. Alternating current is transmitted to the pump motor through an insulated cable extending to the surface. The pump is run on tubing through which well fluid is produced. The motor consists of a multiple number of rotor sections on a common shaft and run in a one-piece stator. The pump is composed of a series of impellers similar to those used in centrifugal pumps. Pumping depth, submergence, and amount and kind of fluid determine the number of impeller stages necessary. This type of pump has been used successfully in pumping relatively large volumes of fluid from wells up to 6,300 ft. in depth.

Several types of hydraulic displacement pumps have developed considerable merit recently [2, 1934]. Oil is forced by means of a surface pump down to and actuating the well pump. The latter consists essentially of a piston run on two strings of concentric tubing, the inner string transmitting fluid from the surface pump. The reciprocating motion of the piston is transferred to a direct-connected pump which, in turn, forces well fluids up the annular space between the two tubing strings.

New developments in rotary positive displacement pumps suggest their ultimate use, singly or by stages, in oil-well pumping [13, 1934]. To compete successfully, the rotary type must possess practically as good overall efficiency as the reciprocating pump and operate at speeds sufficiently high to permit direct connexion to motor with no reduction gear. Such a rotary pump of the internal-gear design directly connected to a similarly designed hydraulic motor promises marked advance in oil-well pumping in the not far distant future.

Classification of Oil-well Plunger Pumps

Oil-well plunger pumps may be grouped under three general classifications, depending upon the manner of attaching the working barrel at the desired pumping depth in the well (Fig. 1):

1. **Common Working-barrel Pumps.** The working barrel of this type pump is stationary and is screwed on to the lower end of the tubing string. The plunger with travelling valve, or valves, is attached to the sucker-rod string, which imparts the necessary reciprocating motion and permits removal of plunger from the well as necessity requires. The standing valve is attached to the bottom collar of the working barrel, and is usually removed by means of a garbutt rod attached to the lower end of the plunger, or, in many cases, by a threaded connexion between valve cage and plunger. Conventional valve cages equipped with balls and seats, or drops ana seats, are used in standing and travelling valves.

The usual common pump plunger body is provided with leather or rubber impregnated canvas cups and steel followers, which effect the necessary fluid seal between plunger and working barrel. The latter may be of cast iron, cold drawn seamless steel, bronze, or other alloy composition.

Several types of stationary working-barrel pumps effect a fluid seal by means of close-fitting cast-iron or steel plungers in lieu of the usual cup-plunger assembly. The working barrel may in some cases consist of a steel tube equipped with sectional machined cast-iron liners. Usually the pump consists of plain steel barrel and cast-iron plunger. The latter may occasionally be provided with cups where the additional seal is thought necessary.

The fluid-packed type of pump is equipped with a plunger, consisting of two concentric tubes telescoping over a third stationary tube attached to the standing valve. The necessary fluid seal is obtained by reason of the unusual length of plunger, rather than by close tolerance between plunger and working barrel.

2. **Insert Pumps.** The insert pump, complete with working barrel and standing valve, is lowered to the desired pumping depth on the sucker-rod string. The tubing string is equipped with a suitable shoe which engages the seating device attached to the standing-valve body and working-barrel or stationary plunger, thereby holding them stationary with respect to tubing during pumping operations.

Insert pumps which depend upon valve cups or packing (repacks) for proper fluid seal may be reclassified into two groups: (1) stationary working barrels with travelling plungers, and (2) inverted travelling working barrels with hollow stationary plunger tubes.

The stationary working-barrel type insert pump may be equipped with travelling plunger provided with cups only, or with cups and repack. The pump may also be of the stuffing-box type with cupped travelling plunger and stationary repack, or it may be of the stationary repack type with close-fitting steel plunger in lieu of cups for further effecting fluid seal.

The inverted travelling working-barrel inserted pump is equipped with hollow stationary plunger tube attached to upper part of standing-valve cage. Cups, or cups and repack, may be used optionally. In this case the working barrel or outer tube travels over the stationary plunger. In other words, the pump resembles the stationary working-barrel type when inverted or turned upside down.

Insert pumps not employing cup or repack plungers, but depending upon close-fitting metallic plungers, are often of the sectional machined cast-iron liner, steel jacket, and steel plunger-tube construction. These pumps may be reclassified into two groups: (1) stationary working-barrel travelling-plunger type, and (2) inverted travelling working-barrel stationary plunger type.

The fluid-packed type of insert pump is similar in design to the usual patented pump run on tubing, described previously, with the exception that it seats in a suitable seating shoe, and is run into the well on the sucker-rod string (Fig. 2).

3. **Casing Pumps.** As the name implies, casing pumps eliminate the use of tubing in the pumping well, and are run to the desired pumping depth on the sucker rods. The working barrel is held in place by means of suitable packers which expand against the casing walls. A general type is similar in design to the common type pump, having a cupped plunger travelling in a stationary working barrel.

Pumping Efficiency—General

Pumping (volumetric) efficiency is defined as the ratio of fluid volume produced to pump displacement. Where the length of stroke is measured at the polished rod, errors may result in calculating displacement and volumetric efficiency, by reason of the differences in plunger travel incident to rod and tubing stretch. In general, pumping efficiency is influenced by depth of well; gravity, temperature, and viscosity of fluid; submergence, gas produced, type and size of plunger and valves, size of tubing

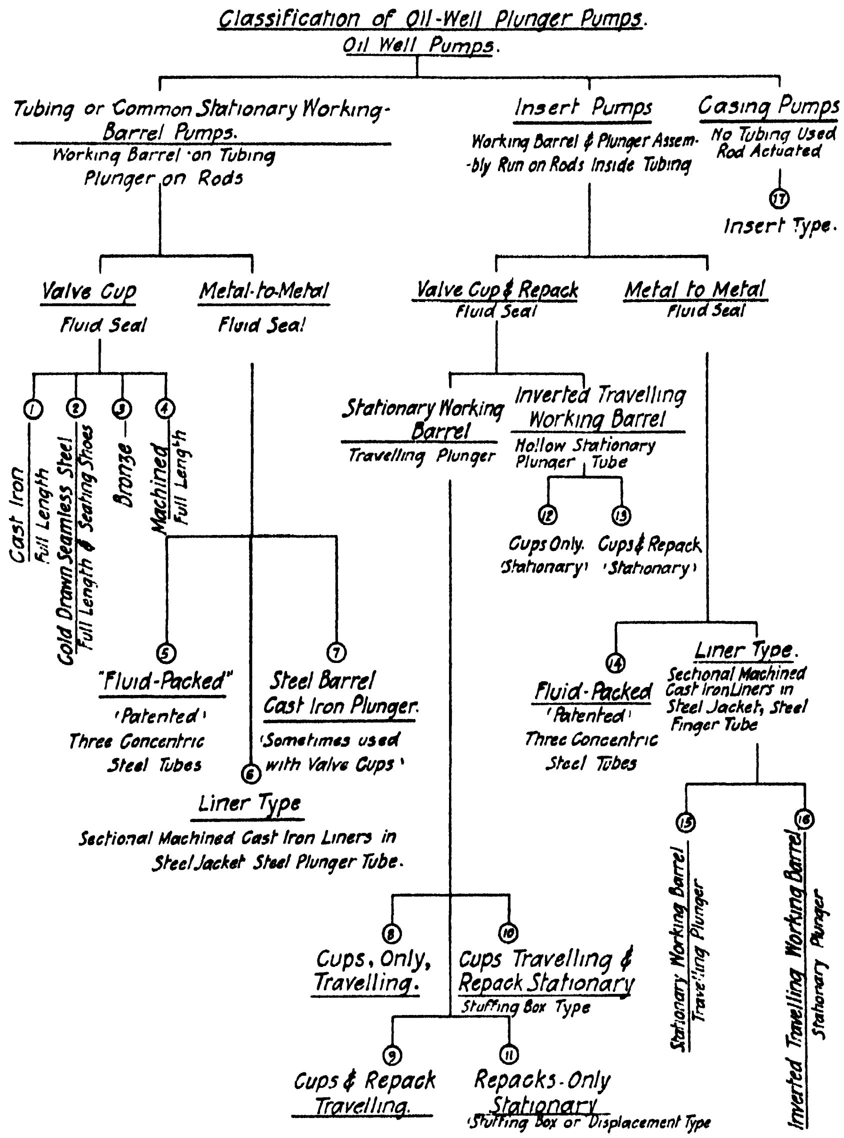

FIG. 1.

and rods, pumping cycle, abrasives, precipitates such as 'gyp' and paraffin, corrosive agents, and pumping motion.

The pump should be selected to meet the particular characteristics of the well. Where the pumping efficiency is unusually high, production may be increased often by increasing the displacement. The various factors causing low volumetric efficiencies will be discussed more in detail in a later part of this article. Where all measures possible have been taken to increase efficiency in relation to a given displacement, the latter may often be reduced and its related efficiency increased by reducing pumping stroke, and/or speed, and by installing a pump of smaller diameter. Reduction of excess displacement may, in some cases,

increase the rate of production, decrease maintenance costs, and reduce emulsion formation and power costs. Where wells are pumped relatively fast at intermittent pumping periods, and the pump submergence is reduced to a minimum, the plunger often strikes the fluid in the partially filled space between standing and travelling valves and 'pounds'. This operation causes excessive pump wear, emulsion, and increased pulling and maintenance costs. The remedy may be found in reduction of displacement per cycle and extension of the pumping period.

In deep wells production can be increased by reducing plunger diameter, and hence rod stretch, to a certain point, since the gain due to reduction of rod stretch is greater than the loss due to reduction of plunger diameter. Beyond this point, however, the gain due to rod-stretch reduction is less than the loss due to reduction of plunger diameter, and production is reduced accordingly. The use of small-diameter pumps, with increase in pumping time, permits lower initial pump investment and reduces rod and surface-equipment stresses, thereby also reducing maintenance costs. However, scale, 'gyp' deposits, paraffin, and low-gravity oils may limit the use of the smaller pumps.

Several methods have been proposed for estimating plunger travel where rod stretch is of consequence [11, 1931]. Where special tests are necessary, rod and tubing scratchers have been used to advantage in determining rod and tubing movement at the well bottom.

Excessive stuffing-box pressures at the wellhead impose unduly high loads on the pumping equipment. Recording pressure gauges on the lead lines have served to indicate causes of losses in volumetric efficiency, especially where several wells are pumped together into the same manifold [11, 1931]. Drops in pressure may indicate worn cups, leaky valves, parted rods, worn plunger, or leaky tubing.

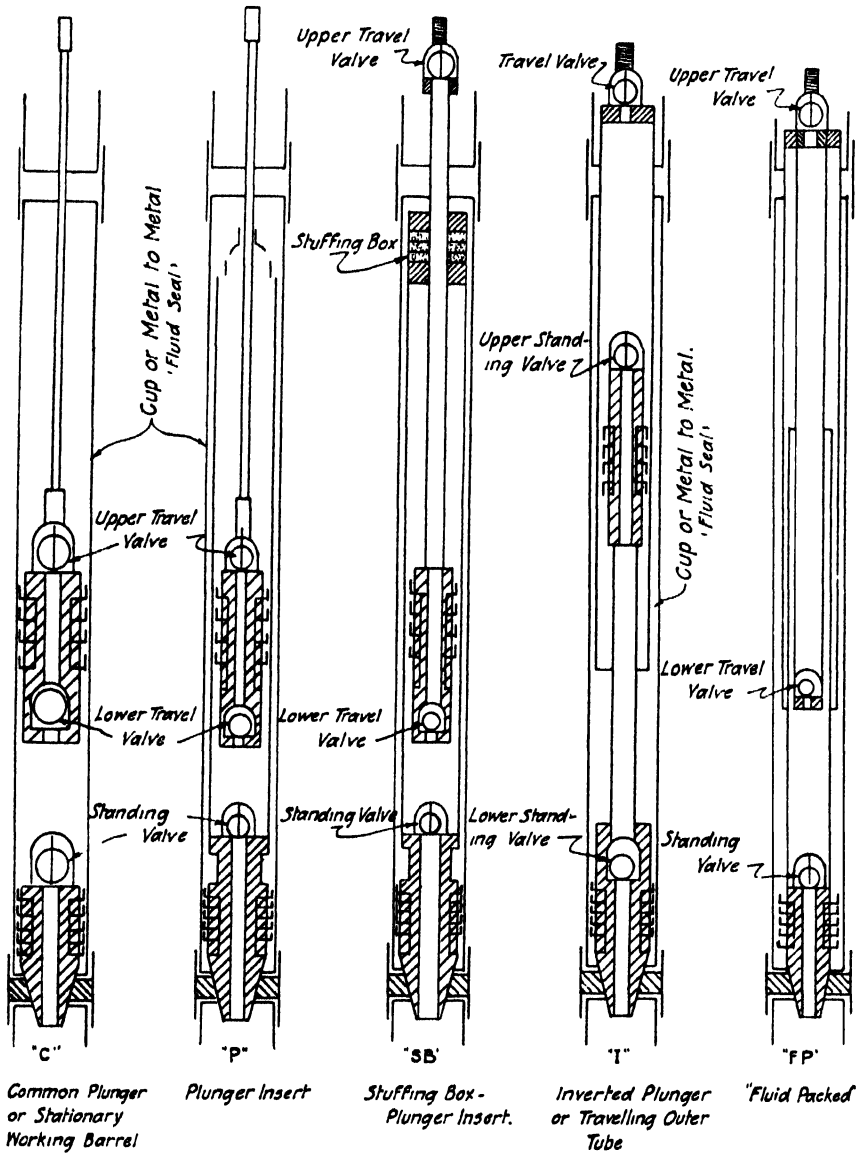

FIG. 2.

Effect of Submergence on Pump Efficiency

The vertical distance from the fluid level outside the tubing to the standing valve of the pump during pumping operations is a measure of fluid submergence. Adequate submergence is requisite to efficient oil-well pumping, and depends upon viscosity and gravity of well fluids, amount of gas produced with the oil, frictional resistance of the pumping system, and displacement of the pump. Too great a submergence may impose excessive back pressure on the producing formation, thereby restricting influx of oil into the well bore. Too little submergence may result in reduced pump efficiency, and, in some cases, formation of paraffin, 'gyp', and other clogging substances on the uncovered sand-face. Hence, the correct pump position ensures a proper balance between displacement efficiency, formation productivity, and utilization of formation energy.

Where the submergence is low, the suction effected by the ascending plunger greatly influences pump efficiency. If gas enters the space between the standing and travelling valves under these circumstances, suction is greatly reduced. A greater submergence then becomes necessary to pump the well efficiently.

The proper pumping depth is usually determined by raising and lowering tubing until a position is found resulting in maximum rate of production. Pressure gradient curves drawn from well-depth pressure surveys are sometimes useful in ascertaining correct pumping depth and determining points of gas influx into the well. Actual pump-operating submergence may be determined by properly designed fluid-level indicators. A depth-recording pressure gauge inserted in the anchor below the standing

valve shows well pressures and submergence during the pumping period, and affords accurate data for the study of fluid levels in relation to volumetric efficiency.

The correct pumping position in wells producing considerable quantities of gas is also determined by adjusting tubing until gas flows steadily from the casing-head. The amount of gas measured at intervals indicates whether gas is collecting in the pump and tubing or is flowing steadily from the annular space between tubing and casing.

Effect of Pumping Rate on Pump Efficiency

The rate of pumping, in terms of complete reversals of plunger stroke per minute, has a linear relationship to displacement, within certain limits. The latter depend upon the productive capacity of the well, the pressures outside the pump, the pressures between standing and travelling valves, and the frictional losses through the anchors and the standing valve. However, beyond a critical speed, the straight-line relationship no longer obtains [8, 1928]. The rods and pump plunger must be given sufficient time to drop through the fluid freely owing to the acceleration of gravity. This prevents rod buckling, and affords sufficient time for the plunger to compress the fluid between the standing and the travelling valves to the pressure in the tubing, thereby permitting the latter valves to open efficiently. At the higher speeds insufficient time for valve functioning, losses in plunger travel due to rod and tubing stretch, increased frictional losses through the pump, and increased compression of gas released from solution in the oil result in lessened pump efficiency and/or displacement, other factors remaining equal. Slippage between the plunger and the working barrel of high-gravity fluids in particular, and at low plunger velocities, promotes low volumetric efficiency. Increased pumping speed up to a certain point produces turbulence, decreases slippage, and thereby increases efficiency. It is, therefore, desirable to obtain a pumping motion whereby the upstroke is sufficiently rapid to reduce slippage. The downstroke should be sufficiently slow to prevent vibration peaks in the pumping load. The time interval at the bottom of the stroke should permit efficient valve action.

The long, slow stroke is preferred to the short, rapid stroke, the principal advantage being in deferred valve action. In many cases it is adapted to wells having low gas volume, but where large volumes of water are produced with the oil. High inertia loads, due to rapid pumping, are reduced in the long, slow stroke of equal displacement. The life of the working barrel and valves is inversely proportional to the number of strokes per minute and independent of the length of stroke. Accelerative forces are proportional to the square of the pumping speed. Hence, for the same production the longer and slower stroke will require less power, with greater economies in pump, rod, and rig maintenance.

The proper pumping rate bears a definite relationship to the critical submergence of the pump, which results in the maximum production of the well over the 24-hour period. This requires that the pump displacement should equal the maximum rate of drainage of fluid into the well consistent with maximum economical ultimate recovery.

Effect of Gas on Pumping Efficiency

Gas may enter the plunger pump as free gas, or it may be liberated from solution in the oil by reason of reduced pressure in the space between the standing and the travelling valves. Displacement is reduced when part of the downstroke of the plunger is required to compress gas, admitted through the standing valve, to the pressure of the fluid above the travelling valve. On the upstroke, the gas within the pump must be expanded to a sufficiently low pressure to permit the fluid below the standing valve to enter. This results in delayed valve action and loss of effective plunger stroke. So-called 'gas lock' occurs when the gas between the standing and the travelling valves expands and is compressed during the pumping cycle. In this operation the valves remain closed.

Pump inefficiency due to gas or gas lock may be overcome wholly, or in part, by several methods. Spacing to permit close approach of the standing and the travelling valves at the end of the downstroke results in a decrease of clearance volume. The travelling valve should be placed in the lower end of the plunger to afford further less space for expansion and contraction of gas. Sufficient fluid head should be maintained above the pump in the casing to prevent 'pulling vacuum', and a sufficiently low pressure at the casing-head is essential for escape of gas through the annular space between the tubing and the casing. The percentage of effective plunger stroke may be increased by increasing the length of stroke. The maximum casing-head pressure permitted depends upon the pumping-fluid level, which, in turn, depends upon the formation pressure and permeability. Experiments show that the greatest casing-head pressures permissible are on wells which fill up quickly to a high static fluid level, with the pump set at a maximum distance below. Accordingly, the pumping-fluid level is not permitted to be depressed below the standing valve. This results in a reduction of gas produced with the oil.

Gas separation is effected ordinarily by causing the fluid to flow downwards through the annular space between two concentric tubes, the gas escaping upwards through holes above the fluid inlet. The ideal gas anchor should entirely surround the working barrel, oil and gas entering the anchor just below the pumping-fluid level opposite the top of the pump. This design provides a maximum distance of oil travel downwards in separating from the gas. In addition, the pump is permitted to fill with maximum submergence, with the entering fluid at a minimum pressure. This facilitates liberation of gas into the annular space between tubing and casing. Notable increases in oil pumped have been reported from wells using this anchor. However, this type can be used only where the diameter of oil string permits. Ordinarily, gas anchors are attached to the pump below the standing valve. A special type has been devised in an attempt to retain the desirable features of the ideal anchor. This anchor has two entrance chambers instead of the one in the ordinary type, and is provided with openings separate from entrances for the escape of gas [25, 1929].

On the other hand, if some casing-head pressure is held on heading wells, agitation may be effected by pumping, causing flow at a rate greater than that indicated by the displacement of the pump. No gas anchor is used in this operation, and the amount of casing-head pressure necessary is determined experimentally.

Sand Influx and Efficiency

Where sand is produced with the fluids from oil reservoirs, it may in some instances be pumped. In other circumstances it may be the best practice to exclude as much sand as possible from the pump and to permit it to collect

in the well, or in traps, for subsequent disposal. Other situations may require that part of the sand be pumped and part excluded. Free sand from the formation in pumping wells varies in texture from very fine, or 'floating sand', to coarse, heavy particles. The grains may be well rounded or sharp and angular. The sand particles may be very loosely cemented and flow suspended in the well fluids. On the other hand, producing sands may be so well cemented as to cause little trouble, except for a short period after shooting and cleaning-out operations.

A high pumping-fluid level is often used to prevent disintegration of poorly cemented sand-faces. Occasionally it is necessary to place the pump at a height compelling the well to produce against considerable back pressure. Where large cavities are formed in wells as a result of sand removal, the reduced fluid velocities, incident to the increased wall area, lower the fluid sand-carrying capacities, and thereby reduce sand movement into the well.

Where it is necessary to pump quantities of sand with the well fluid, pump designs should ensure fluid velocities of sufficient sand-carrying capacities and with a minimum number of recesses for sand accumulation. Inasmuch as sand-carrying capacity varies as a power of the velocity, minimum cross-sectional areas consistent with general pump efficiency and impact abrasion are essential. Besides abrading the working surfaces, accumulated sand prevents valves from seating and impedes oil movement. Where wells are operated part time, the sand, on settling, often 'freezes' the plunger in the working barrel. In such wells, continuous operation or special pumping equipment is necessary to prevent sanding up and consequent pulling for repairs.

Various types of underground equipment have been designed to combat sand trouble. Traps in combination with gas anchors have been used profitably to exclude sand from the pumps, although disposal of the accumulated sand required frequent pulling of tubing. The 'fluid-packed' type pump handles sand with minimum wear. The wide clearance between plunger and barrel permits comparatively little sand abrasion, common to pumps with close-fitting plungers. The inverted type pump prevents sand settling on or in the barrel, and around the plunger and standing valve. A special type pump is surrounded with a sand trap consisting of a series of concentric tubes about the working barrel. Fluid is pumped from the travelling valve through the trap and into the tubing, the sand settling in the trap instead of on top of the plunger and travelling valve. A newly improved type pump for combating sand troubles is provided with a close-fitting nitrided steel plunger, operating through soft packing in a stuffing-box. A plunger guide above the latter, and operating in an upper extension of the working barrel, prevents side thrust on the stuffing-box bearings. Absence of dead oil space directly above the entrance to the stuffing-box is responsible for non-settling of sand on the plunger and stuffing-box bearings.

Sand has little opportunity to lodge between the plunger and working barrel where a long barrel is used with a plunger just equal to the length of stroke. When the standing valve is placed in a special extension shoe connected with the lower collar of the working barrel, the sand gathering about the valve has difficult access to the working barrel and more continuous operation is effected. Sometimes a plunger extension is provided with cups on top, and on both top and bottom, of the steel plunger as a protection against sand abrasion. In some instances cups and short plunger have given acceptable service in sandy wells where the steel plunger failed to function. Various circulating pumps have been proposed for handling sand with the oil. Clean oil is forced down outside the production tubing string, lubricating the plunger and increasing the volume and sand-carrying capacity of the ascending fluid.

Various screen liners in use for excluding sand from the pump are not wholly effective. However, where the proper mesh has been selected for the free-running sands, proper bridging of the sand grains outside the liner results, and minimum quantities of sand are pumped with the well fluids [24, 1933].

Influence of Pump Design on Service

Efficient oil-well pumping requires that the manufacturers design plunger pumps of adequate strength and of proper abrasion- and corrosion-resisting materials. The general design of the pump should permit efficient fluid flow with minimum friction losses. Pump valves, cages, and plungers should be of proper design to meet the imposed conditions of flow and load. Working-barrel tubes should be of smooth interior surface and uniform diameter. They should be of sufficient tensile strength to prevent distortion under operating pressures. Tubing threads should be of adequate size and number to prevent failure.

Although the steel plunger type pump is used extensively in California, the cup type of pump is more common where the lighter gravity oils are pumped, inasmuch as they are usually more effective in reducing slippage between plunger and working barrel. From the standpoint of wear, there is some indication that the repack type is more satisfactory than the cup plunger pump.

Metallic Plunger Pumps.

Metallic plungers and liners are ground to very close tolerance limits which may of necessity be less than one-thousandth of an inch. Plungers must be of sufficiently loose fit to avoid excessive heating and consequent binding by expansion. However, they should be sufficiently tight to prevent fluid slippage under pressures ranging up to 2,000 lb. per sq. in. Plunger slippage tests made by connecting pumps to a source of fluid pressure aid in the installation of satisfactory pumps. Metallic plungers are furnished in such sizes that successive increases in working-barrel bore due to wear may be compensated for by selecting a plunger of such diameter to effect the clearance desired. Corrugated plungers have been effective in reducing slippage, but their tendency to collect sand has limited their use in many wells. Well temperatures may cause unequal expansion of plunger and barrel, if they are made of different materials, thereby changing the desired clearance. Ordinarily, at normal well temperatures no unusual trouble should be met. However, where temperatures vary greatly, as in gassy wells, it may become difficult to make plunger replacements where tolerances are close and coefficients of expansion of metals in plunger and working barrel are not the same.

Where high fluid pressures exist, the clearance space between hollow steel plunger and working barrel may be reduced by expansion of the plunger walls on the downstroke, and increased by contraction of the plunger walls on the upstroke. This difficulty may be overcome by placing the travelling valve at the bottom instead of at the top of the plunger, or travelling valves may be placed at both top and bottom. The full fluid pressure will thereby expand the plunger when the working barrel expands, ensuring

more suitable clearances during the up-and-down stroke, with consequent reduction of leakage losses [19, 1928].

Improper lubrication of the steel plunger surface may result in overheating, binding, and consequent excessive wear. As a means of providing better lubrication, a spiral groove is sometimes cut in the plunger surface, beginning at the top and extending to a point near the middle. Another spiral groove is cut from a point near the middle and extending to the bottom.

Corrosion-resistant Working Barrels.

The inner surface of working-barrel tubes is made rough by reason of abrasives, fluid leakage, and corrosion. The latter results in an unusually rough surface of the common steel working barrel, causing rapid scoring of the plunger or destruction of the cups.

Several corrosion-resistant materials are used for working barrels operated where hydrogen sulphide or other corrosive agents are present [14, 1933]. These materials include: (1) nickel, (2) chromium-nickel alloys, (3) brass and bronze, (4) steel and iron. Where air mixes with hydrogen sulphide in certain wells the corrosive effect is greatly accelerated, which requires that the working barrels be made from nickel or chromium-nickel alloys. The latter, containing approximately 18% chromium and 8% nickel, are generally known as 'stainless steels'. The cost of stainless-steel barrels is reduced by fabricating a composite barrel, consisting of a tube of polished stainless steel cold pressed in a steel jacket. Brass and bronze barrels are successful in pumping non-sulphide corrosive brines, but are not highly resistant to abrasion. Electroplating steel barrel interiors with chromium has, in some cases, aided in resisting corrosion and abrasion. However, successful chromium plating depends largely on the process used, thickness and character of the plating, and manner in which the barrel surface is finished.

Pump Valves.

Pump valves should be designed to act quickly and positively, with maximum resistance to abrasion and corrosion, and minimum restriction to fluid movements. Free admission of oil requires that the valves have time to function properly in the interval between stroke reversals with minimum leakage past the seats. Short passages of large cross-sectional area from the valve seat up and through the cage reduce turbulence and increase the fill-up of the pump during the suction stroke. Over-size standing valves reduce frictional losses and, accordingly, promote higher pump efficiency. Excepting pumping of heavy viscous oils at comparatively low speeds, the high-lift pump valve causes balls to pound the seats severely and roll out the cage wings. The high lift also reduces effective plunger travel. For ordinary pumping conditions, valve-cage wings should permit the ball to lift until the area for passage of fluid above the seat is slightly greater than the area of the seat opening. The space within the valve cage should permit the ball to rise and seat freely, but with minimum lift and clearance.

Light hollow balls rise more quickly and do not pound out seats as rapidly as the heavier solid type. The hollow plumb-bob type has been used to some extent, but the drop and seat type has proved to be of great benefit where cage battering and pounding of seats by balls caused excessive trouble.

Valve seats should be press fitted and not driven into the standing-valve bodies, thereby preventing distortion, cracking, and consequent leakage.

Pump valves should be vacuum and pressure tested before installation to forestall leakage.

In view of the severe abrasive pounding and chattering action to which pump valves are subjected, it is essential that hard non-corrosive materials, having a tough interior composition, be used to prevent wear, cracking, corrosion, or distortion.

Balls and seats are ordinarily made of (1) tool steel, (2) commercial bronze, (3) chromium and chromium-nickel alloys, and (4) special alloys such as hardened K-monel metal [14, 1933]. In the past, tool-steel balls and seats were used universally, but the deeper, heavier wells, producing corrosive and abrasive fluids, required the use of alloy metals of physical and chemical properties adequate to meet the new conditions imposed. Commercial bronze valves are highly corrosion resistant to non-sulphide brines, but are not recommended where hydrogen sulphide or abrasive materials are present. However, due to non-magnetic properties, commercial bronze valves function in certain wells where tool-steel valves become magnetized. The use of bronze balls and seats is therefore limited. Stainless-steel balls and seats have given good general service with high resistance to abrasion and corrosion. Although some failures have occurred from sand cutting, very little corrosion has been noted, except where air was admitted to small-capacity wells producing hydrogen sulphide, or where sulphide embrittlement caused chipping and fracturing. Although the cost of stainless balls and seats is comparatively high, yet the increased service and the possibility of extended use by regrinding encourage their purchase. K-monel metal balls and seats are reported to show good service in shallow wells producing hydrogen sulphide. Other types, such as nitrided and chromium-plated balls and seats, are undergoing further experimentation in an attempt to find the most economical installation for the various conditions existing in pumping wells.

Pump-valve Cups.

Pump-valve cups are ordinarily fabricated from canvas, impregnated with rubber compound, and vulcanized. Leather cups have been more generally used in the past, but are used only to a limited extent to-day.

Because of the greater hydrostatic pressures existing, the excessive friction caused between expanded cups and working-barrel wall, and the consequent danger of cup collapse, the steel plunger pump has proved to be more satisfactory in the deeper wells, producing little sand and large fluid volumes.

Cups deteriorate in service by softening or disintegrating through the action of well fluids, by the abrasive action of sand, scale, or rust removed from the well, and by abrasion from rough working-barrel surfaces. A considerable proportion of barrel wear is caused by fluid slippage past the cups, which leaves the tube walls more roughly scored than ordinary abrasive effects. Improper size and application of cups permit leakage and reduce pump efficiency. Cups may be so abused prior to or while running into a well as to give comparatively short pumping service. The insert barrel eliminates abuses due to running exposed cups on common type plungers through tubing to working barrel. The number of cups used on the plunger assembly, the existing well temperature, and the character and hardness of the cup material also influence length of service obtained between pulling operations. The greater the pumping depth and

consequent pressures, the greater the number of cups necessary on the plunger assembly.

Excessive clearance between valve bodies and followers on cup plungers permits lost motion, sand accumulation, and leakage past the cups. Valve bodies and followers should be so fitted as to make a slip fit, which should result in decreased trouble and pulling costs.

Pump-repair Shop.

Certain economic benefits arise from a repair shop for refitting, cleaning, and repairing pumps. The repair shop permits more careful gauging for plunger, liner, or tube wear, and proper fitting with the correct size of plungers, or cups, than is possible on the derrick floor. Proper vacuum and pressure testing of balls and seats is facilitated. Experience has also shown the economics of regrinding the more expensive alloy balls and seats. New barrels may be inspected for straightness, uniform diameter, and smoothness, eliminating premature failures not due to factors existing within the well.

Oil-well Tubing

The size of the tubing string, ordinarily varying from 2 to 3 in. in diameter, determines the maximum diameter of pump used. Tubing should be of sufficient cross-sectional area to minimize fluid frictional losses. However, where gas aids in lifting the fluid, tubing sizes should be such as to prevent slippage. The smaller sizes also carry sand more efficiently, due to increased fluid velocities. Tubing should be strong enough, particularly in the joint, to withstand pumping-fatigue stresses. This may require the use of upset tubing, with the greater joint efficiency, in the deeper and heavier wells. In addition, long tubing collars ensure tighter joints and less leakage in the deeper wells by reason of the increased thread contact. The size of tubing selected should permit 'washing over' where this practice is necessary because of sand accumulations. The size of sucker rods used also controls tubing size, inasmuch as the clearance between rod box or coupling and tubing must permit fishing.

Tubing-stress reversals during pumping are caused by alternate support of static and dynamic fluid loads on the downstroke and transfer of fluid load to the plunger on the upstroke. Rod, plunger, and fluid friction on the upstroke further reduce tubing stress. As a result of intermittent load application, elongation of tubing occurs during the downstroke and contraction during the upstroke, thereby modifying the effective amount of plunger movement. Various tubing protectors and hardened couplings are used to reduce casing wear incidental to tubing movement.

The tubing catcher, provided with slips and tapered mandrel, is placed in the tubing string to automatically catch tubing falling as a result of failure or in pulling operations. The catcher may also be provided with an anchoring device for preventing tubing movement. Anchors reduce wear of tubing collars and casing. They also reduce fatigue, especially at the tubing joints. In many cases, plain tubing with anchors may be as safe to run as upset tubing without anchors. The tubing anchor should be set at some distance above the pump, using a predetermined procedure, depending upon depth, size of tubing and pump, pumping cycle, and proper distribution of weight between tubing hanger at surface, and anchor. An increase in production per stroke frequently results following anchoring of tubing [15, 1932]. This is caused by the increased length of stroke made possible by reduction of tubing stretch.

Sucker Rods

No attempt will be made to describe the various sucker-rod designs, compositions, and applications, in view of the available published literature. Wescott [21, 1935] has traced the development of sucker rods and recommended steels of various physical and chemical properties to suit the varying well loads and fatigue influences encountered. Heavier pumping loads encountered in the deeper wells have encouraged the use of combination sucker-rod strings of $\frac{7}{8}$-in., $\frac{3}{4}$-in., and $\frac{5}{8}$-in. rods. Balanced combination strings ensure that the unit pumping stress is the same at the top of each section of different sized rods [23, 1929]. The care of sucker rods and causes of rod failures have been described by Wescott and Collins [22, 1931].

Pumping Loads and Counterbalancing

During the pumping cycle, rod movement is popularly assumed to be simple harmonic, resulting from a seldom-realized constant angular velocity of the crank. On the upstroke the pump plunger is accelerated from zero velocity at the bottom to a maximum speed at some intermediate point between bottom and top of stroke. From the latter point the plunger is accelerated negatively to a position of rest at the top of the stroke [19, 1928]. The downstroke is also characterized by positive acceleration to an intermediate point, and from thence by negative acceleration to the point of rest at the bottom. Simple harmonic motion is seldom realized. Ordinarily, the prime-mover speed is increased on the downstroke. Theoretically, the pitman length should approach infinity to effect the desired motion; whereas, in practice, the short pitman and walking beam cause eccentricity of motion.

The sucker-rod load [6, 1935] on the upstroke is composed, primarily, of the static weight of rods and fluid above plunger, plus the dynamic load incident to acceleration of the static load from position of rest, plus friction of the rods and fluid in the tubing, plus friction of the plunger in working barrel and polished rod in the stuffing-box, minus pressure on the plunger caused by operating fluid level.

The determination of pumping loads as the algebraic sum of the above and other components is complicated by many factors, chief of which are the limitations of force transmittal along the sucker rods and through the fluid column, the effect of tubing stretch on pick-up of fluid load by pump plunger, and the effect of rod stretch which prevents immediate response of the plunger to the reciprocating motion of the walking beam. Contrary to commonly accepted interpretation, other factors than maximum rod acceleration at a given pumping cycle exert a greater influence on peak rod loads. This is evidenced by a study of dynamometer cards which have shown that, whereas the maximum upward acceleration of the polished rod occurred at the start of the upstroke, the peak load occurred near the middle of the upstroke where the rod acceleration was at a minimum value.

In simple harmonic motion, acceleration of the rods varies directly as the length of the stroke and as the square of the number of strokes per minute. Inasmuch as acceleration is inversely proportional to the length of stroke for a given rod speed, the advantage of the long stroke is indicated in reducing excessive rod loads [10, 1932].

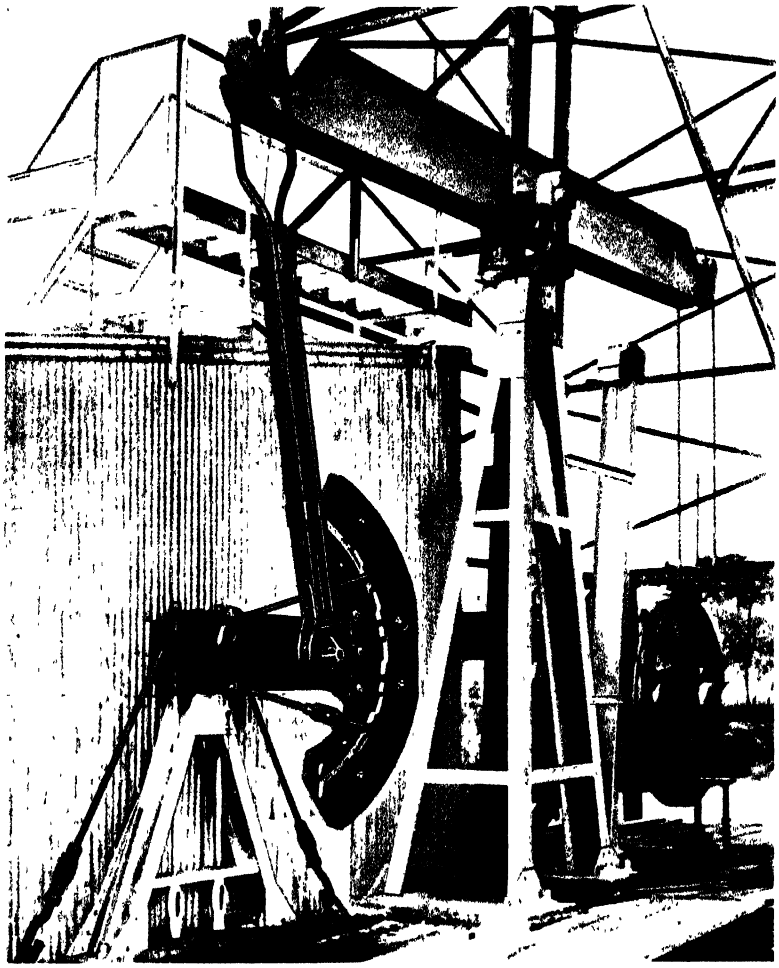

Fig 3

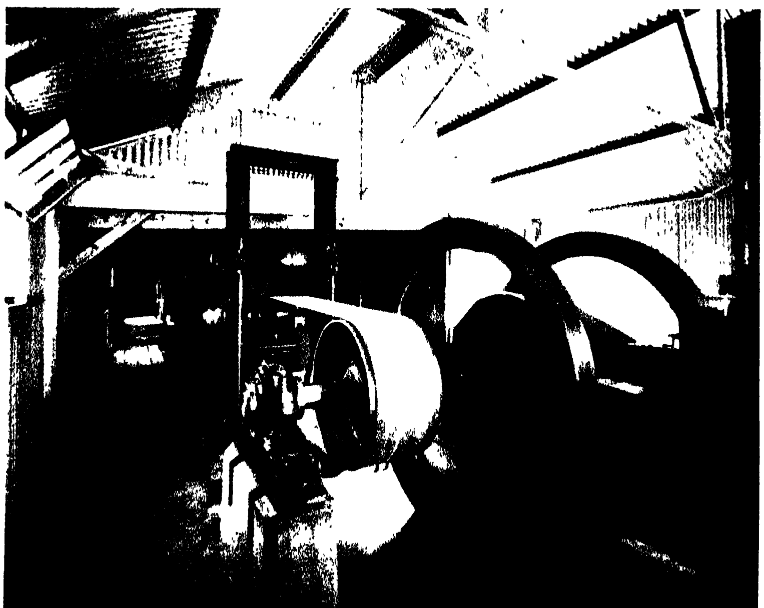

Fig. 4

Ordinary counterbalancing practice results in equal torque peaks of well and counterbalance, with minimum change in angular velocity of the crank [20, 1930]. Power requirements and surface-equipment maintenance are thereby reduced. The power end of the transmission equipment is more readily affected by changes in counterbalance than the polished rod end. The correct amount of counterbalance for power savings does not always result in the best pumping motion. However, counterbalancing for both power savings and well performance reduces excessive rod acceleration and dynamic loads, decreases overall maintenance, effects some reduction in power requirements, and often promotes greater pump efficiency [18, 1929]. A change in the counterbalance without altering the pumping cycle may result in more production per stroke by permitting the plunger to slow down at the bottom and top of stroke, ensuring pump valves sufficient time to open and close properly. The counterbalance torque for the overall best pumping condition will, therefore, be slightly less than the well torque.

Neglecting acceleration, friction, gas, shock loads due to loose wrist pins, loose centre irons, and other unusual operating conditions, the most efficient counterbalance for power consumption is approximately equal to the rod weight plus one-half the difference between fluid load and weight of fluid displaced by the rods [18, 1929]. By weighing the well with a recording dynamometer the correct amount of counterbalance can be determined, since all factors affecting rod loading are reflected. In conformance with the foregoing, the correct counterbalance weight for power consumption determinable from the dynamometer card is equal to the load on the downstroke plus one-half the difference between the load on the upstroke and downstroke. This is equal to the load represented by the mean height of the card.

The fluctuating loads caused by accelerative forces in each half-stroke are not wholly compensated for by counterbalancing. A fly-wheel interposed in the transmission system divides the load between different points on each stroke and returns some of the energy stored when power demands are light to the system when power demands are heavy. This permits the engine speed to be kept more nearly uniform [9, 1933]. The internal-combustion engine usually is equipped with sufficiently heavy fly-wheels to serve the aforementioned purpose. Unless they are designed to transmit increased loads, reduction gears used successfully with an electric motor drive may not function economically when driven by a single-cylinder internal-combustion engine with heavy fly-wheels. The latter promotes much higher torsional stresses in the transmission equipment than does the motor drive with comparatively small inertias.

Counterbalances are grouped into five general types: (1) beam, (2) rotary, (3) pitman, (4) grasshopper, and (5) band-wheel. The beam-type balance has gained considerable favour on wells operating at slow and average pumping speeds. The limited space on the walking beam for its installation and the high inertia forces causing whip of the beam due to reversals of stress at the higher speeds have influenced some operators to adopt other types. Many operators prefer the rotary-type balance on fast long-stroke wells, contending that it gives maximum beneficial inertia or fly-wheel effect for the protection of the surface equipment interposed between the prime mover and the crank. The principal gain of concentrating counterbalance weight at the crank lies in the diminished second harmonic of the torque as compared with other types of counterbalances [4, 1930] (Fig. 3). A disadvantage cited for the rotary balance is that the effective balance decreases as the length of stroke increases. Accordingly, it is impossible to install sufficient balance for occasional heavy wells [18, 1929]. A net horizontal shaking force incident to rotary balancing may in some instances be detrimental, especially where the rig front is mounted on piling. Practically equal effectiveness may be obtained with beam- or rotary-type balances. The rotary type imposes stresses in the crankshaft and jack posts due to centrifugal force. Where the well is properly counterbalanced, the beam-type balance subjects the pitman to alternate tension and compression stresses. When using the beam type, less power is indicated to produce motion than when using the rotary balance, the former inducing two reversals of stress in the shaft each revolution, while the latter may cause three or more. Where the rotary balance is used the pitman is in tension at all times, since the balancing effect is at the wrist pin of the crank. Since rotary- and beam-type counterbalances both have their advantages, it is probable that a combination of the rotary- and beam-type balances would produce the best results.

The pitman counterbalance is suspended directly from the beam. The inertia forces set up by this counterbalance are largely transmitted through the crank to the jack-post bearings, thereby dividing the stresses between walking beam and crankshaft. This type of counterbalance has accelerated pitman and bearing failures at high speeds because of imposed stress reversals at the top of the stroke.

The grasshopper, or cantilever type counterbalance, is equally as effective as the beam type. However, its many moving and space-consuming parts, with their attendant additional upkeep and awkward appearance, encourage the use of the grasshopper balance principally on temporary rig-front installations. The band-wheel counterbalance is not generally preferred because of the unusual stresses imposed and maintenance costs sustained in band-wheel shafts, keys, and bearings [7, 1928–9].

In the standard rig setting the crank centre is usually set directly below the pitman bearing when the walking beam is level, and on a line the same distance from Sampson-post centre line as the well. When operated counter-clockwise, the standard rig affords a mechanical advantage over clockwise rotation because of the angle of the pitman and walking beam at the point of peak loading. However, where the crank centre is moved back and falls on a line at right angles to the operating arm of the walking beam, the set-back position results in the same mechanical advantage operated clockwise as the standard setting with three bearings in line operated clockwise or counterclockwise. Less power, reduced load peaks, less counterbalance, and smoother operation have been reported from such installations [17, 1931].

Power Transmission Efficiencies of Pumping Wells

Pumping, or lift efficiency [16, 1931], is the percentage ratio of calculated work performed in lifting the well fluid, to the power applied to the polished rod, or

$$\text{pumping efficiency} = \frac{\text{hydraulic horse-power}}{\text{polished rod horse-power}},$$

$$\text{hydraulic horse-power} = \frac{5{\cdot}61\,LBW}{33{,}000\times 60},$$

where

L = distance in feet from pumping-fluid level to point of delivery,
B = barrels per hour,
W = weight of fluid in pounds per cu. ft.

It is necessary to weigh the well with a dynamometer before the polished rod horse-power can be calculated.

$$\text{Polished rod horse-power} = \frac{PLAN}{12\times 33{,}000\times I},$$

where P = load in pounds per inch of card height,
L = polished rod stroke in inches,
A = card area in square inches,
N = number of well strokes per minute,
I = card length in inches.

Power-transmission efficiency of pumping rigs is the percentage ratio of polished rod horse-power to power input at the prime mover.

Overall pumping efficiency is the percentage ratio of hydraulic horse-power to power input at the prime mover.

By actual test conducted [18, 1929] on a pumping rig, the electrical input to the motor was measured with a watt-hour meter. The power delivered to the rods was calculated with the aid of dynamometer cards, and the overall power transmission efficiency determined, which varied from 12 to 85%, depending on the load, counterbalancing, and type of drive. It was found that decrease in power is not proportional to decreased polished rod load. Higher power efficiencies were obtained at increased pumping speeds, heavier loads, and more efficient counterbalancing. It has also been observed elsewhere that the horse-power input at the polished rod increases more rapidly than rate of fluid production from the well.

The importance of maintaining maximum pumping and power-transmission efficiencies from the standpoints of low-power requirements and minimum maintenance costs is obvious.

Surface Equipment for Pumping Wells

Extensive literature is available describing various types of reciprocating pumping equipment, including standard wooden fronts, improved steel fronts, chain-driven fronts, geared speed-reduction units, pneumatic heads, hydraulic heads, rotating pumping units, and direct-lift pumpers. Accordingly, discussion of pumping equipment will be brief.

Although surface equipment is ordinarily selected to take care of polished rod horse-power requirements adequately, increased attention has been devoted to the reciprocating motion imparted, and the reduction of rig friction, misalinement, and vibrational stresses, thereby reducing surface and subsurface maintenance costs and increasing fluid production. The mechanical efficiency of steel fronts has been increased materially by means of the 'three bearings in line' walking beam, the practicability and durability of which is becoming more thoroughly understood through extended application. The use of this beam results in minimum horizontal travel of beam-hanger bearing with consequent reduction of hanger troubles. Inasmuch as the pitman bearing is on the same centre line as the Sampson-post and beam-hanger bearings, the same angularity of the pitman is effected, regardless of the direction of operation. This eliminates the back-setting of jack-post bearings previously described. Improved types of pitman, beam-hanger, and Sampson-post bearings are now furnished rain and dust proof, and are provided with removable bushings and oil reservoirs, the latter eliminating frequent hand lubrication.

Adjustable steel pitmans ensure proper angularity of the walking beam above and below the horizontal centre line. The use of anti-friction wrist-pin bearings reduces starting torques, facilitates easy removal of pitman from the crank, and results in decreased bearing maintenance costs.

Satisfactory speed ratios between band-wheel and prime mover are effected by means of an interposed countershaft drive, using endless belts and idlers from engine to countershaft, and from the latter to the band-wheel (Fig. 4). Although the initial investment is greater than the direct drive from engine to band-wheel, maintenance costs are greatly reduced by permitting the prime mover to operate at the proper speed. Belt costs are reduced by reason of correct size of pulleys and speed of travel.

Increased attention recently has been directed to so-called 'portable' geared units, generally belted directly to electric motors and occasionally to multi-cylinder internal-combustion engines. The value of reclaimable material is generally higher than that of ordinary pumping fronts. Geared pumping units of adequate rating have given satisfactory service on the lighter wells. The ever-increasing number installed on the heavier wells should afford adequate data concerning their economical cost of operation as compared with standard fronts over a normal pumping life.

Prime movers suitable for oil-well pumping have been adequately described [1, 1932; 5, 1931]. Initial investment, power and maintenance costs, well pulling and reconditioning requirements, rig efficiency, and polished rod horse-power output are the factors ordinarily considered in the selection of the proper prime mover.

Marked recent improvements have been made in rod-line pumping, particularly in the design of geared powers, and multiple well pumping from the 'back-side crank' of standard pumping fronts. The proper balancing of the power with the aid of the dynamometer has been aptly described [12, 1932]. Although prior practice has limited rod-line pumping to the shallower wells, recently improved equipment has permitted its application to the deeper wells, especially where restricted production has minimized the need of individual well equipment capable of operating at well capacity.

Economics of Oil-well Pumping

Surface-equipment investment may be relatively great if heavy well loads, large volumes of fluid, and long productive life are expected. Substantial unrecoverable investment in foundations may be justified where amortization is made over a long period. However, where the productive life is relatively short, maximum reclaimable equipment is desirable. Often the more expensive pumping equipment proves to be the most economical when continued uninterrupted service results in reduced maintenance and power costs, with consequent reduction of down time and loss of oil production. On the other hand, it may be more economical to keep the initial investment low if light loads, low fluid volumes, and short productive life are expected. The most economical pumping front for a given well may be chosen by estimating depreciation, amortization, interest, maintenance, and operating charges over the pumping life.

Improved subsurface equipment likewise often proves

most economical during extended operation. Equipment should be selected in view of the particular well conditions involved.

Accurate trouble and maintenance records on surface and underground equipment are essential to economical selection, replacement, and operation. Cost records assist in the determination of the proper pumping rate. A much higher power and maintenance cost may be expected from intermittent operation at high pumping speeds than with continuous 24-hour slow pumping speeds. Cost and trouble records also indicate excessive well pulling and the need for reconditioning.

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OIL-WELL BAILING

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It is probable that the earliest method devised for lifting water mechanically was an adaptation of the winch and bucket, since mention of such equipment is found far back in history. The shallow depth of early water wells, and a relatively small demand for water, afforded little incentive for improving established lifting methods. Later, a greater demand for water and the necessity of developing deeper sources brought about many improvements in the bucket pump. The most important of these was the development of the filling valve. This application is the first known use of a valve for any purpose, and the bucket pump so equipped essentially constitutes the modern bailer.

The bailer is a tool indispensable to both the churn drill and rotary systems of oil-well drilling, and is as necessary in the producing, reconditioning, and repair of completed wells. It probably has a more varied use than any other drilling tool. For nearly all purposes, the bailer is operated by a sand reel or hoisting drum to which it is connected with a flexible wire line. This line, called the sand line, runs from the sand reel over a pulley at the top of the derrick, so that the bailer is suspended from it over the centre of the well. The sand reel is driven from the band-wheel by a friction wheel, or is driven by sprockets and chain from the band-wheel shaft, depending upon the type of rig and other conditions. Hoists, or reels, for bailing vary in size, design, and method of drive according to the type or rig, or the purpose of bailing.

Use of the Bailer in Drilling

It becomes necessary when drilling with cable tools to remove the bit cuttings periodically, otherwise the accumulation would prevent free motion, and eventually would cause the tools to stick. The frequency of bailing is governed by the rate of drilling, the nature of the formation penetrated, and the amount of fluid in the hole, as well as by the physical properties of the fluid. When the bailer (Fig. 1) is run, an alternate raising and lowering a few feet after bottom has been reached agitates the fluid, and facilitates the passage of coarse particles through the valve. A considerable suction usually is necessary to remove the cuttings when sand has been drilled, because of the tendency of sand particles to settle compactly, and under such conditions a modification of the bailer, called a sand pump (Fig. 2), is used. The bailer is better adapted to handle material of a fluid consistency than the sand pump, but is not as effective in removing sand and coarse cuttings. Usually it is necessary to make several runs with the bailer or sand pump before the hole is sufficiently clean for drilling to proceed.

Drilling bailers are made in various diameters and lengths. Most commonly they are constructed of seamless steel tubing with a bail riveted to the upper end, and a reinforcing shoe riveted or screwed to the bottom. Sectional bailers (Fig. 3) are constructed with screw joints; and they may be assembled in any desired length. The valve seat is formed at the top of the shoe. Valves are of several types such as disk, clapper, and spherically seated. The spherically seated valve usually is made with a stem projecting downwards below the bottom of the bailer. The projecting stem is for the purpose of centring the valve, or for unseating it when the bailer is filled or dumped. The stem-equipped valve, commonly called a dart valve, is used almost exclusively in drilling bailers.

Use of the Bailer in Cementing

A number of special bailers have been designed for lowering and dumping material such as explosives, water, or cement. The pouring of water into a hole, for instance, tends to cause caving, so that it often is necessary to lower it with a bailer. The use of a bailer with a valve at the top as well as at the bottom is sometimes necessary to prevent loss of fluid, as in lowering water into a well making a large amount of gas. The bailer dump, which consists of a yoke, the upper end of which straddles and attaches to the bailer dart, and the lower end of which is threaded to receive small-diameter pipe, is used with a dart-valve bailer when it is desired to dump material a given distance off bottom. In order to dump a bailer of water, for instance, if there is fluid in the hole, and, in any case, in order to empty it completely, the use of the bailer dump is necessary.

One method of cementing casing and several kinds of repair and reconditioning jobs require the placement of cement at the bottom of a hole. The presence of a considerable amount of fluid makes dumping very difficult with a common bailer. For the reason that positive dump action is essential to the success of cement jobs, a number of special bailers have been designed to handle cement. A typical bailer for this purpose (Fig. 4) has a cone-shaped valve at the bottom that is held in the closed position, when lowering, by attachment to the sand line through a long link straddling the bail. The link is provided with a latch that passes the bail as a result of slack in the line after bottom is reached. Upon hoisting, the weight of the bailer is transferred from the valve to the bail by means of the latch, thus allowing the contents of the bailer to be dumped. A variation of this bailer is described by Tough [5, 1918]. Other types of dump bailers include a glass-bottom bailer described by Thompson [4, 1921], and a sleeve-action shoe that is attached to the shell of a common bailer in place of the bailer valve.

Use of the Bailer in the Repair and Reconditioning of Oil-wells

Although bailers and sand pumps are used for removing fluid and detritus from a well during its repair, the only application worthy of description is the use of the bailer as a casing tester. In the past considerable trouble was experienced from leaky casing, and in some areas the practice of testing a string of casing before cementing was followed. In testing a string of casing the bailer is run to different depths in order to locate the points at which the casing may be defective; the purpose of the bailer being to catch water that may be leaking through. At present the casing tester is used mainly for locating leaks in old wells when the fluid can be bailed down, since practically no

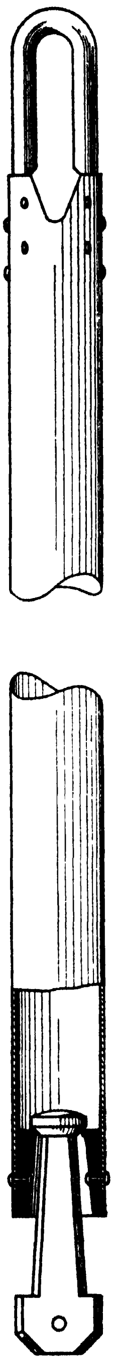

FIG. 1. Common bailer.

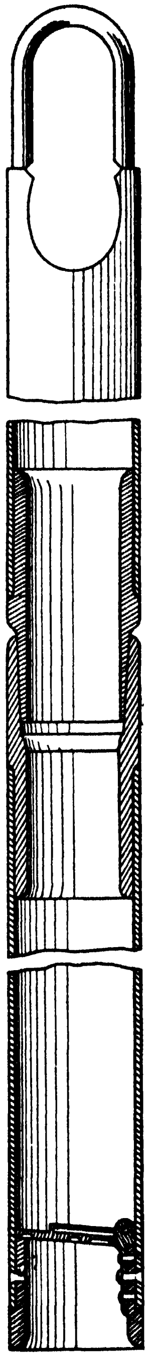

FIG. 2 (*a*). Common or California type sand pump.

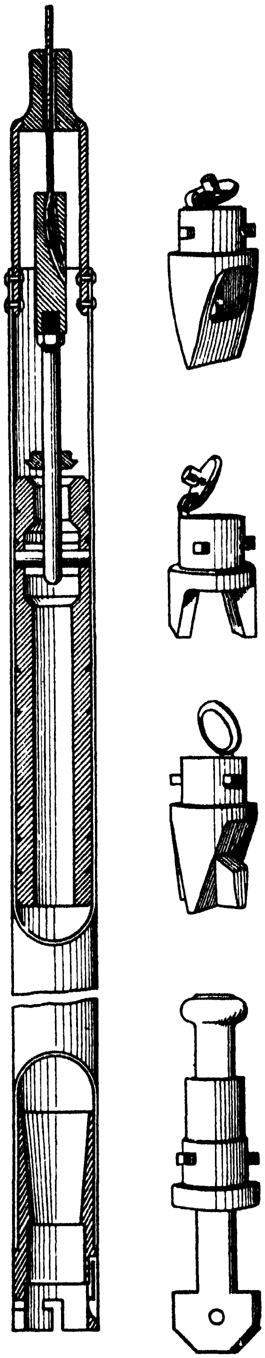

FIG. 2 (*b*). Sand pump with interchangeable bottoms.

trouble has been experienced in recent years with new casing. The swab bailer, described by Swigart and Beecher [2, 1923] is superior to the common bailer for locating casing leaks.

Bailing is widely used as a means of reconditioning. Flowing wells often accumulate considerable sand as well as small amounts of water, and not infrequently rotary mud or drilling fluid is left in the hole at the time of completion. When such accumulations occur they are removed, usually with a bailer or sand pump, as soon as violent flow ceases. Old wells often accumulate a sticky agglomeration of shale, sand, paraffin, swab rubbers, scale, &c. It is customary to raise tubing, as the accumulation progresses, until oil production becomes so reduced that removal of the detritus becomes necessary for continued operation. Accumulation of fine sand alone, frequently associated with the first showing of water in a well, may cause excessive cutting of pump parts. Such conditions very commonly are remedied by bailing and sand pumping.

The profitable operation of many wells pumping a few barrels of oil a day is made possible by occasional bailing. Many such wells are pumped from central power plants, and are not equipped with derricks. The equipment at beam-operated wells often is unsuited to the use of either rotary or cable tools. It is under these conditions that bailing and the use of the bailing unit are most favourable, since the pay-out of the expense for repair to equipment, for rigging up, and for the use of clean-out tools would be of long, if not of indefinite duration.

Among the factors influencing the volumetric efficiency of oil-well pumps, submergence is one of the most important. It must be conceded, in recognition of this fact, that pumping efficiency is impaired by a considerable fill-up of cavings in wells of low fluid level. The primary criterion for bailing is thus established. Irrespective of fluid level, an accumulation of cavings, scale, or other material inside screens, strainers, or perforated liners will close the openings, thus restricting the supply of oil within the well. An accumulation of cavings in wells completed without liners or screens is less apt to affect production. The production of wells having fluid levels of the order of 100 ft. or more off bottom often is not increased by bailing. On the other hand, many wells of lower fluid levels respond to bailing when the accumulation of cavings is so small as to seem unimportant, particularly if a tendency to salt incrustation is present.

Bailing alone is seldom undertaken after shooting. For years the sand pump has been used when suction is needed for the removal of accumulations. The hydrostatic bailer (Fig. 5) develops a much higher suction under favourable conditions. The operating principle makes use of the difference in pressure of the atmosphere and the pressure exerted at the bottom of a fluid column. This bailer is constructed in such manner that the fluid compartment remains at atmospheric pressure until it reaches bottom where a valve is opened. The differential pressure, which may be as great as 100 atm. in deep wells, causes material to flow with considerable violence into the filling chamber. A fluid column of sufficient head to exert a differential pressure of about 7½ atm. is recommended as the minimum condition favourable to operation. This amounts roughly to about 400 ft. of oil. This type of bailer has been used successfully in California fields, in the Oklahoma City field, in the Gulf Coast area, as well as in South America and other foreign countries. Its use has been extended successfully to the cleaning out of wells after shooting.

Another tool that might be classed as a bailer is the mud socket (Fig. 6). Although this device is run in the place of a bit in a string of cable tools, its purpose is to remove mud or clayey material that may have accumulated in a well. It is used with or without a chisel bottom, and is churned up and down in operation until filled, when it is withdrawn to be emptied. The mud socket is used both in drilling and in cleaning out.

The economic aspect of bailing can be illustrated by the result of bailing a group of five wells. These wells are about 2,750 ft. deep and had an average daily production of 7·7 barrels per well per day before bailing. Production after bailing averaged 11·6 barrels per well, an average increase of 3·9 barrels per well-day. The amount of cavings removed averaged 10·6 ft. per well, and bailing time averaged 18 days of two 6-hour tours per well. Bailing was done with a tractor equipped with a winch. The tools used were bailers and sand pumps. In addition to the increased production, there resulted from bailing a considerably decreased frequency of well pulling.

Another group of 46 wells bailed had an average production of 6·8 barrels per well per day before bailing, and an average production of 10·3 barrels afterward. At the end of the year during which these wells were bailed, production averaged 9·7 barrels per well per day, and at the end of the following year production averaged 8·8 barrels per well. Wells in this group ranged in depth from 2,000 to 3,500 ft., and produced variously from seven different sands. The cost of bailing depends upon a number of factors such as depth, amount of cavings to be removed, and type of equipment. Obviously, bailing costs have little significance without a consideration of the related variables. As a generalization, it may be stated that the cost of bailing a well is nominal, since in many instances only a few days' time is required.

Bailing as a Production Method

The production of oil from highly unconsolidated sands presents many difficulties, particularly where the sand content exceeds a few per cent., and when the sand has floating characteristics. Ordinarily, mixtures of sand and oil cannot be pumped to advantage because of the abrasive action of the sand particles on the pumping mechanism. A very high sand content characterizes the oil produced in Roumania and in some parts of Russia, amounts as great as 40% by weight having been observed. As a consequence of this condition, wells, in the past, were designed for bailer operation. In parts of the United States and South America, although unconsolidated sands are prevalent, the sand content of the oil produced generally is not great, and the depths at which production is found are such as to make the cost of large diameter construction as well as the cost of bailing prohibitive. Instead of bailing, screens and strainers are used as a rule to exclude the sand. While some bailing has been done in the United States, this method has not had an extensive application. An interesting electrically operated automatic bailing installation in the Kern River, California, field has been described by Huguenin [1, 1922].

Production bailing, because it is a continuous operation, requires a hoisting drum of greater ruggedness and capacity than the sand reel used in drilling and reconditioning; but bailing drums differ from sand reels only in size, greater brake capacity, and in higher clutch efficiency. Bailing drums commonly are belt driven through a countershaft from an electric motor or steam engine. The bailing line

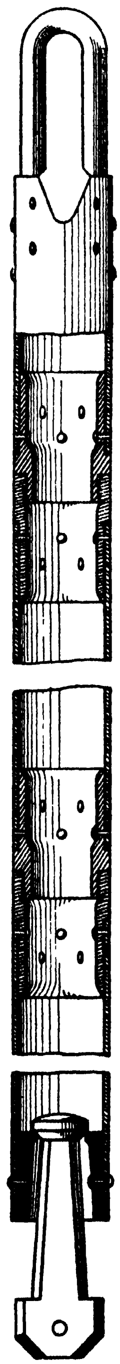

Fig. 3. Sectional bailer.

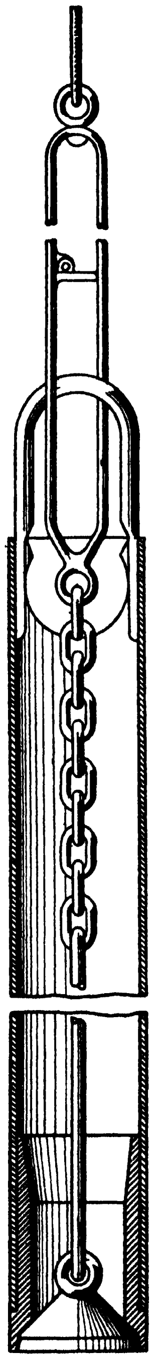

Fig. 4. Dump bailer.

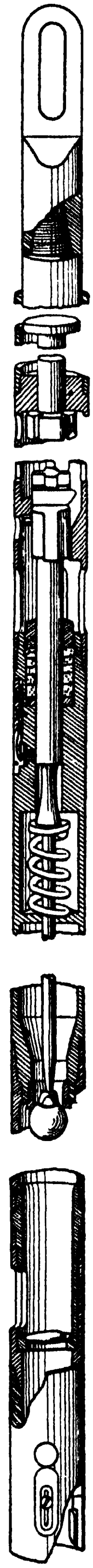

Fig. 5. Hydrostatic bailer.

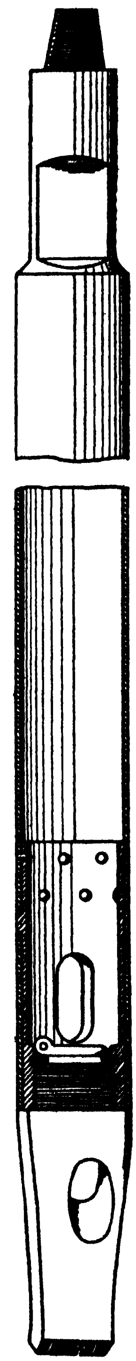

Fig. 6. Mud socket.

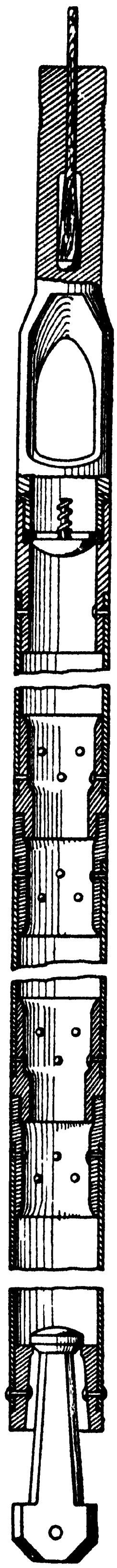

Fig. 7. Top-valve bailer.

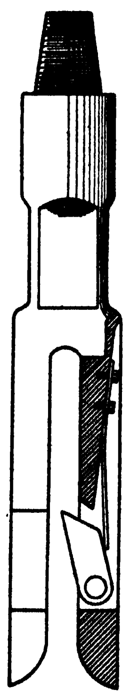

Fig. 8. Latch jack.

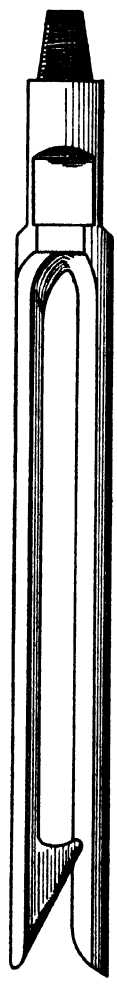

Fig. 9. Bailer grab.

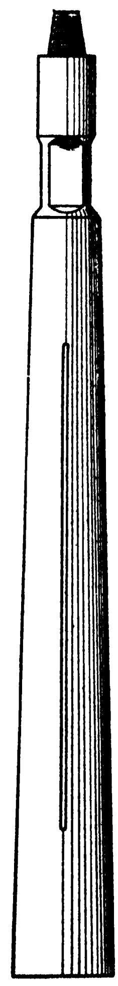

Fig. 10. Horn socket

runs over a pulley, usually of large diameter, at the top of the derrick, and attaches to the bailer by means of a hitch or a swivel socket (Fig. 7).

In areas where production is bailed, the wells are completed with a string of large-diameter casing set at the top of the sand. The additional expense of this construction is offset to some extent by the relatively shallow depths at which production is found. The depths of bailing wells will range from a few hundred feet to depths not greatly exceeding 2,000 ft. Many wells flow their production initially, and again flow when deepened; but these wells are bailed as soon as natural flow has subsided. Occasional heading and flowing after bailing has been started is one of the hazards of the method.

The bailers used generally are larger than drilling bailers in order that a large volume of fluid can be handled per trip. Sizes range from 6 to 18 in. in diameter, and from 20 to 60 ft. in length. Otherwise production bailers are but slightly different from drilling bailers, except for the use occasionally of flexible or jointed bailers in crooked holes, and the use of the top valve (Fig. 7), when a considerable amount of gas is present in the oil. In operation the bailer is lowered rapidly until near the surface of the oil, when the speed is retarded in order to reduce the impact and to avoid kinking the line as a result of too much slack. After the bailer has been immersed for a few seconds, hoisting is commenced. The hoisting speed is kept low while the bailer is in the fluid so as not to create excessive suction. Too great a suction, or too much agitation, is apt to start violent flow in some wells, and such flows usually damage the bailer and line, and are dangerous otherwise at the surface because of the large amount of gas liberated.

The hoisting speed will range between 1,000 and 1,500 ft. per minute after leaving the fluid. At the surface, fluid is dumped from the bailer into a sluice or tank. It is necessary to run the bailer to bottom periodically in order to prevent an accumulation of sand, or of water when it is present. The frequency of runs to the bottom varies with the amount of sand or water, or with other conditions. The number of trips made per hour usually varies from 20 to 30, depending on depth and other considerations.

Bailing is an inefficient production method because of the dead weight of line and bailer, because of the intermittent nature of the process, because a high per cent. of the fluid lifted consists of sand, and because of the low volumetric efficiency of the bailer itself. The weight of a 12-in. bailer 40 ft. long is from 1,000 to 1,500 lb., and hundreds of tons of sand alone may be raised from a well daily. A part of the contents of a bailer is lost as the bailer leaves the fluid because of reduced pressure and release of gas. When the amount of gas in solution is sufficiently great, it is necessary to use a double-valve bailer to prevent violent ejection. A small relief valve is used with the double-valve bailer in order that pressure will have been reduced gradually before the bailer reaches the surface.

Thompson [3, 1925] gives the mechanical efficiency of bailing as 14% in the Baku district. This is determined from an average horse-power output per well of 21·5, and an average amount of work done equivalent to 6,000 lb. per hour raised 1,000 ft., which includes the weight of the rope, bailer, sand, and oil, as well as the resistance of the fluid column to the movement of the bailer through it. Under favourable conditions, bailing efficiency will run as high as 35%, based on the power expended at the hoist and the power represented by the weight of the oil produced.

The Recovery of Lost Bailers

An ever-present and the commonest hazard of bailing is that of losing the bailer. Loss may result from caving, from sticking in a tight or crooked hole as the result of a parted line or broken bail; or, occasionally, as the result of an unloosened fastening. In this connexion the use of wire line clamps on the free end of the line is generally avoided in favour of lashing with soft rope, since the clamps might freeze the bailer, in case of a broken line, by falling between the bailer and the casing.

Ordinarily the recovery of a bailer is accomplished easily with a latch jack (Fig. 8) or bailer grab (Fig. 9), since this tool readily engages the bail. Greater difficulty results if the bail gives way, and in such cases a horn socket, slip socket, or casing spear may be successful. Fortunately, bailers are drilled up or sidetracked easily, so that protracted fishing jobs seldom occur as the result of their loss.

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STAGE SEPARATION OF CRUDE OIL-GAS MIXTURES

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University of Oklahoma

The Physical State of the Underground Reservoir

THE petroleum industry produces its raw materials in the form of crude oil and gas which are lifted from underground reservoirs either by natural flow, gas-lift, water drive, or by various pumping methods. In these reservoirs the petroleum hydrocarbons may be present in:

(1) A liquefied state.
(2) A gaseous state.
(3) Liquid and gaseous phases.

During the early life of the industry most of the oil and gas was produced from shallow wells, and the problem of separating the liquid phase (crude oil) from the gaseous constituents received little attention. The rapidly increasing consumption of petroleum products since the outbreak of the World War, however, has forced the drilling of deeper wells in order to provide an ample supply of oil. The cost of producing this crude oil has increased geometrically with the greater depths from which the oil is lifted. The deeper reservoirs were found to have higher pressures, which meant that the hydrocarbons might be present underground in a different physical state than they were after being brought to the surface. It is gradually being recognized by petroleum engineers that a knowledge of the physical state of the reservoir, both in its original state and at various times during the producing life of the field, is needed in order to be able to conserve the potential energy stored up in the underground strata and to prolong in an intelligent manner the natural flowing periods of the wells. It is quite pertinent to know whether the propulsive force which is causing the oil to flow to the surface may be either the result of the expansion of hydrocarbon gases coming out of solution from the reservoir crude oil, or the effect of the encroachment of edge-water. Extraneous or free gas caps existing above the liquid in a pool or possibly in other formations may also be considered a factor in furthering the flow of oil, since the expansive force of these gases as they enter the drill-hole along with the oil may furnish energy in a manner similar to that of flowing a well artificially by gas-lift.

The East Texas Field

Although a very high percentage of oilfield reservoirs contain hydrocarbons both in liquid and in the gaseous phases, it is interesting to know that there are notable exceptions to this rule. For example, the East Texas field, which to date is the largest oilfield ever discovered in the United States, produces oil with a very low formational gas-oil ratio. The crude oil itself is undersaturated with gas under the conditions existing in the reservoir; therefore nothing but liquefied hydrocarbons are present in the reservoir, and will continue to remain as liquid until the pressure falls to 750 lb. per sq. in. abs., below which gas will begin to come out of solution. Since the discovery of the field, the bottom-hole pressures have declined from about 1,600 down to 1,200 lb. per sq. in. abs. The driving force which has caused this field to flow by natural means for such a long period with a very small decline in reservoir pressure may be due to the expansion of underground water which extends outwards for a long distance in the Woodbine Sand and outcrops some 50 miles to the north, west, and south of the oilfield proper. Schilthuis and Hurst [14, 1934] have made a thorough study of this large field, and have come to the conclusion that the original pressure would be substantially returned to the reservoir were the field shut in.

The Oklahoma City Field

The Wilcox Zone of the Oklahoma City field is another exception in that no gas cap was found when the field was first discovered. Unlike East Texas, however, the Oklahoma City bottom-hole fluid was found to be saturated at the original reservoir pressure of 2,640 lb. per sq. in. abs. This coincidence of saturation of a liquid with no gas cap present is quite an unusual phenomenon, and would tend to make one believe that a small gas cap must have been present, but was not detected by drilling operations. It was observed, however, that a very high percentage of the wells produced initially at a gas-oil ratio of 800 to 900 cu. ft. of gas (standard conditions 14·7 lb. per sq. in. abs. and 60° F.) per barrel of actual or residual crude, and that this ratio was only slightly higher than that obtained by releasing the dissolved gas differentially from a sample of the bottom-hole crude, from 2,640 lb. per sq. in abs. (original reservoir pressure) down to atmospheric pressure. Since the crude oil produced at the wells was not flashed differentially, it would be only natural to expect a higher gas-oil ratio than that obtained in the laboratory by differential release of dissolved gas.

Fundamental Research

Lindsly [10, 1933] has conducted extensive researches in the study of the physical state of reservoir fluids, and the manner in which they behave when dissolved gases are released differentially from bottom-hole samples. Dow and Calkin [5, 1926] have carried out investigations on the solubilities of gases in crude oil. Various other engineers and scientists have done work on this problem, and at the present time many research laboratories both in industry and in universities are spending much money and effort in obtaining an accurate knowledge of the properties of hydrocarbons under high pressures comparable to those present in deep oilfield reservoirs. Lacy *et al.* [8, 1934] have done some fundamental research work on the behaviour of less complex mixtures of hydrocarbons in an attempt to simplify the problem and reduce it to a scientific basis. The Universal Oil Products Company donated a large sum of money to the American Petroleum Institute for the purpose of carrying out fundamental research in the various branches of the petroleum industry. The work which Lacey and his co-workers have done was carried out under one of these projects. Cope and Lewis [4, 1931], and Brown, Souders, *et al.* [2, 1932] have contributed much towards the knowledge of the deviations of hydrocarbons at high pressure from the so-called perfect gas and solution laws. Katz and

Brown [7, 1933] have published original data showing the equilibrium relationships of petroleum hydrocarbons in vapour-liquid systems. All of this fundamental research, only a part of which has been mentioned above, has enabled the oil industry to produce oil and gas in a far more scientific manner than that which was common practice as late as 5 or 10 years ago.

The Production of Oil and Gas

Before 1925 practically all crude oil was produced directly into storage tanks under atmospheric pressure, where the extraneous gas and a large part of the dissolved vapours were released to the air. About this time gas-lift operations were introduced on a large scale in the Seminole field in central Oklahoma. This new method of prolonging the flowing period of the oil-wells called for conservation of the gas, which in turn was processed through natural gasoline plants and recycled back into the tubing, or the annular space between the tubing and the casing, to lift the oil to the surface. Other developments in the industry caused changes in the producing methods to take place in rapid order. Economical operation made it necessary for the producer to conserve the energy within the reservoir by keeping the ratio of gas to oil as low as possible. Large flush production in various parts of the United States forced regulatory measures, such as proration, to be adopted in order to keep the supply of crude oil and gas in line with the demand for petroleum products.

The Need for High-pressure Separators

These developments brought on the practice of flowing wells under back-pressures, well above atmospheric, and necessitated the installation of oil and gas separators. The early installations usually involved the use of one separator between the well and the atmospheric storage tank. With the development of the Kettleman Hills field in California came the practice of multi-stage separation, where as many as three or four separators are connected in series, the oil or gasoline condensate flowing consecutively from the bottom of each separator into another one having a lower pressure until it finally flashes into atmospheric or vapour-tight tanks having a few ounces of back-pressure.

Mechanical Difficulties

Many mechanical difficulties have had to be overcome to make the operation of these separators fool-proof and automatic.

Entrainment

Baffles of widely different design are to be found among the various makes of separators. The purpose of these baffles is to reduced the entrainment or mechanical carrying over of liquid droplets of crude oil into the exit gas-stream. The incoming stream of oil and gas is usually given a whirl by allowing it to enter the separator tangentially. The centrifugal force throws the liquid against the inner surface of the separator, while the gas, having a much lower momentum, tends to rise. As the gas rises through the shell it meets various baffles or mist extractors which either give it further centrifugal whirls or cause it to take a zigzag path through alternating blinds and open spaces. As the mist and liquid droplets are separated from the gas-stream an attempt is made to divert the liquid away from the rising gas-stream into a separate down-spout leading to the liquid reservoir at the base of the separator. Failure to include this principle offsets a large part of the good accomplished by the mist extractor, since the descending liquid is caught in the ascending stream of gas and thrown upwards again.

There are few published data to show the amount of entrainment which takes place in separators. Matheny *et al.* [11, 1935] have reported results of entrainment tests made by Hickman, of the Black, Sivalls, and Bryson Corporation, in the Fitts pool of Oklahoma. These data are shown in Fig. 1, where entrainment in gallons of crude oil per

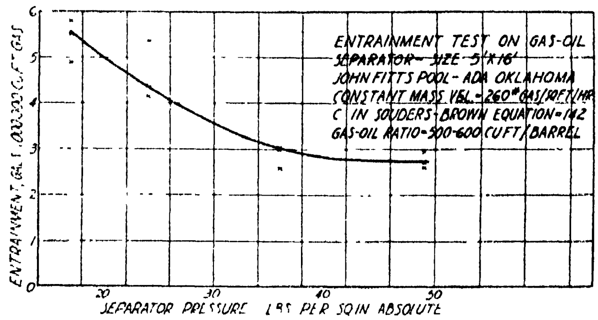

FIG. 1.

1,000,000 cu. ft. of gas (standard conditions) is plotted as a function of separator pressure for a constant mass velocity of 260 lb. of gas per sq. ft. per hr. Although the data are somewhat scattered, it is easy to see that the entrainment increases geometrically with decreasing separator pressure. This increase in entrainment is due not only to the higher linear velocity at lower separator pressure, but also to the vigorous frothing of the crude oil as the heavier natural-gasoline fractions come out of solution. Raising the froth level has the same effect as reducing the free space in which the liquid droplets have a chance to separate themselves from the dry vapour. Souders and Brown [16, 1934] have developed an equation, giving the relationship between mass velocity and the densities of the vapour and liquid to be separated.

$$W = C[d_2(d_1-d_2)]^{\frac{1}{2}},$$

where W = mass velocity of vapour in lb. per sq. ft. per hr.,
C = a constant,
d_2 = density of vapour in lb. per cu. ft.,
d_1 = density of liquid droplets in lb. per cu. ft.

Carey [3, 1934] offers an equation in which linear velocity is given as a function of the vapour and liquid densities.

$$U = K\left[\frac{\text{liquid density}}{\text{vapour density}}\right]^{\frac{1}{2}},$$

where U = linear velocity in ft. per sec.,
K = a constant.

These equations apply to incipient entrainment, and represent a balance between the upward and downward forces acting on the liquid droplets. The laboratory results of several recent investigations [1, 1934; 6, 1934; 13, 1935; 15, 1935; 16, 1934] show that entrainment falls off very rapidly with increasing space between bubble plates in fractionating towers and absorbers. Therefore in the design of gas-oil separators one would likewise expect the same advantages to be gained by providing ample free space between the liquid reservoir in the bottom of the separator and the mist extractor located near the top. There are several methods which are used in the quantitative determination of entrainment, such as titration, discoloration, and gravimetric measurements. For the measurement of entrained crude oil mist the use of glass wool is the most

suitable, the increase in weight representing the amount of entrainment. When it is necessary to measure entrainment under pressure, this method has its disadvantages in that the sampling tube should be kept under the operating pressure until after it is weighed in order to prevent evaporation losses. It might be found satisfactory to release the pressure and measure the degree of entrainment by comparing the discoloration caused by the residual crude left on the glass wool with a sample of liquid discoloured with a known amount of similar crude oil. Glass wool has been found to be one of the most nearly ideal scrubbing agents for finely divided crude mists because of the ease with which it is wetted. Difference in electro-potential between the charges on the crude particles and the glass wool may be the cause of the neutralization of the electrical charges and the resultant deposition of the crude oil on the surface of the glass wool.

Other Problems involved in the Design and Operation of Separators.

(1) **Sand-cutting.** Fine sand from the producing horizon may be lifted in large quantities from depths as great as 6,400 ft. whenever a well is producing oil and gas at a high rate. The abrasive action of the sand is so marked that large gate valves have been destroyed within a few hours' time. In the separators a thick baffle-plate is placed in front of the incoming stream of oil, gas, and sand. One company has obtained patents on a tell-tale baffle-plate which will give a warning whenever the sand cuts through the plate. A space behind the protecting plate is provided so that the liquid draining down the walls of the separator will not be disturbed by the impact of the incoming stream of oil and gas. To remove the sand continuously from the separator is another problem. The conventional throttling float-valve has become obsolete, since the sand must go through such a valve at too high a velocity. A diaphragm valve which opens wide and closes tight intermittently has been found to be quite satisfactory for the handling of suspended sand.

(2) **Removal of Crude Oil from the Separator to Storage.** Fig. 2 shows a cross-sectional view of an oil-gas separator with a direct-operated kidney float-valve. This type of valve is being replaced to a large extent by float-valves located inside the separator and connected with hollow tubing to a valve equipped with a diaphragm. It is one problem to separate the oil from the gas within the separator, and another one to transfer the oil to storage. The chief requirement placed on the liquid-level control valve is to see that nothing but liquid is allowed to leave the tank. To permit gas to escape would not only entail the loss of the gas, but also a reduction in the API. (American Petroleum Institute) gravity of the crude oil, to say nothing of the added hazard of fire. It is the practice to locate the separator as near the well as possible with a minimum of bends in the flow line. If the crude-oil storage tanks are located at a distance from the well, a pipeline adequate in size to handle the oil production should be installed, otherwise it may be necessary to hold a pressure in excess of the amount desired in order to force the oil to storage. When the permissible back-pressure against which a well can flow falls to 3 or 4 lb. per sq. in. gauge, it is either necessary to elevate the separator or to install a vacuum trap which can intermittently remove the oil, no matter how low the pressure may fall on the separator. The vacuum trap may cost more than elevating the separator, but it has the advantage of being able to take care of the removal of the crude oil from the separator should high vacuum be desired.

Friction Loss through the Separator

The loss in pressure between the base of the separator and the point where the gas leaves the vessel must of necessity be less than the hydrostatic head of the crude oil between the level of the crude oil in the base of the separator and the point where it is collected in the mist extractor or spray condenser. If the pressure drop is greater than this hydrostatic head, the liquid crude would be forced from the base up into the mist extractor causing the separator to prime.

Strength and Safety

Welded separators are taking the place of riveted vessels in the same way that welding has gained in favour for all types of pressure vessels. Welding costs about the same as riveting, but welding requires skill and expensive equipment which only the larger manufacturing companies can provide, and, at the same time, the purchaser must be assured that he is obtaining a separator which will come up to the guarantee. Special low-temperature annealing ovens (see Fig. 3) are required to relieve all possible strains which may be set up as the result of rapid cooling after the welding is done.

All separators must be equipped with safety-valves which should be regularly tested. Several things may happen which a safety-valve cannot take care of:

(1) The well may increase its flow so suddenly that the safety-valve and gas-exit line cannot take care of the gas volume.
(2) Paraffin or ice may accumulate in the base or around the mist extractor during cold weather, causing an excessive pressure to build up in the separator below the mist extractor.
(3) Paraffin or ice may clog up or freeze the unloading spring in the safety-valve and prevent it from functioning.

One equipment company has realized these dangers and has overcome them by placing safety-heads, fitted with rupture plates or disks, both on the side and in the top of the separator. These rupture disks are more nearly foolproof and at the same time provide a much greater relief capacity than that afforded by the somewhat constricted gas passage through the safety-valve.

The Importance of Stage Separation to the Oil Producer

The price of crude oil is governed to a certain extent by its API. gravity, since the higher the gravity the greater the percentage of gasoline present. Although cracking processes have caused the low API. gravity crude oils to yield fairly high percentages of gasoline, there is still a premium placed on the higher gravity crude oils amounting to as much as 2 cents per degree API. between ranges of as much as 5 or 10 degrees. Soon after pressure separators were put into operation, it was observed that the crude oil produced, by the dropping of the pressure in stages, had a higher gravity than the oil which was flashed directly from the flowing well into an atmospheric storage tank. Furthermore, it was found that this crude oil produced by stage separation did not evaporate appreciably faster than the oil produced by the early practice of flowing directly into atmospheric storage. Although it has long since been known to the refining industry that flash vaporization always yields a greater quantity of vapour than by differen-

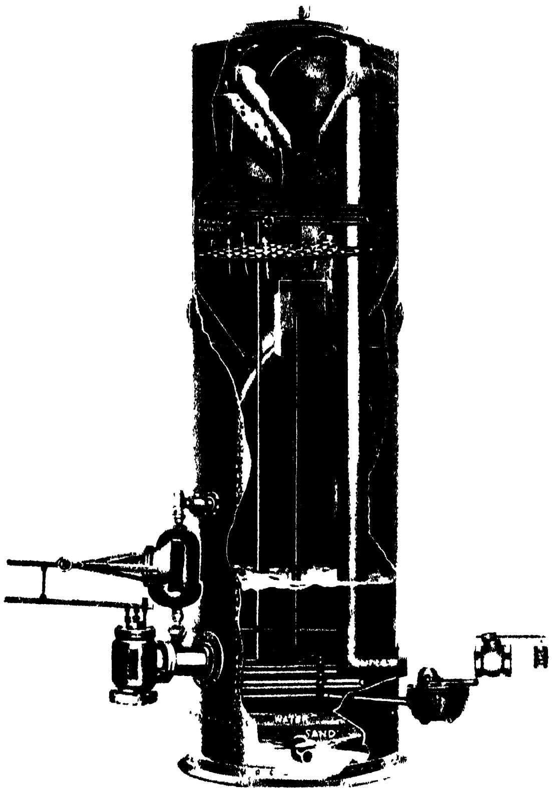

FIG. 2 Oil-gas separator equipped with outside kidney float

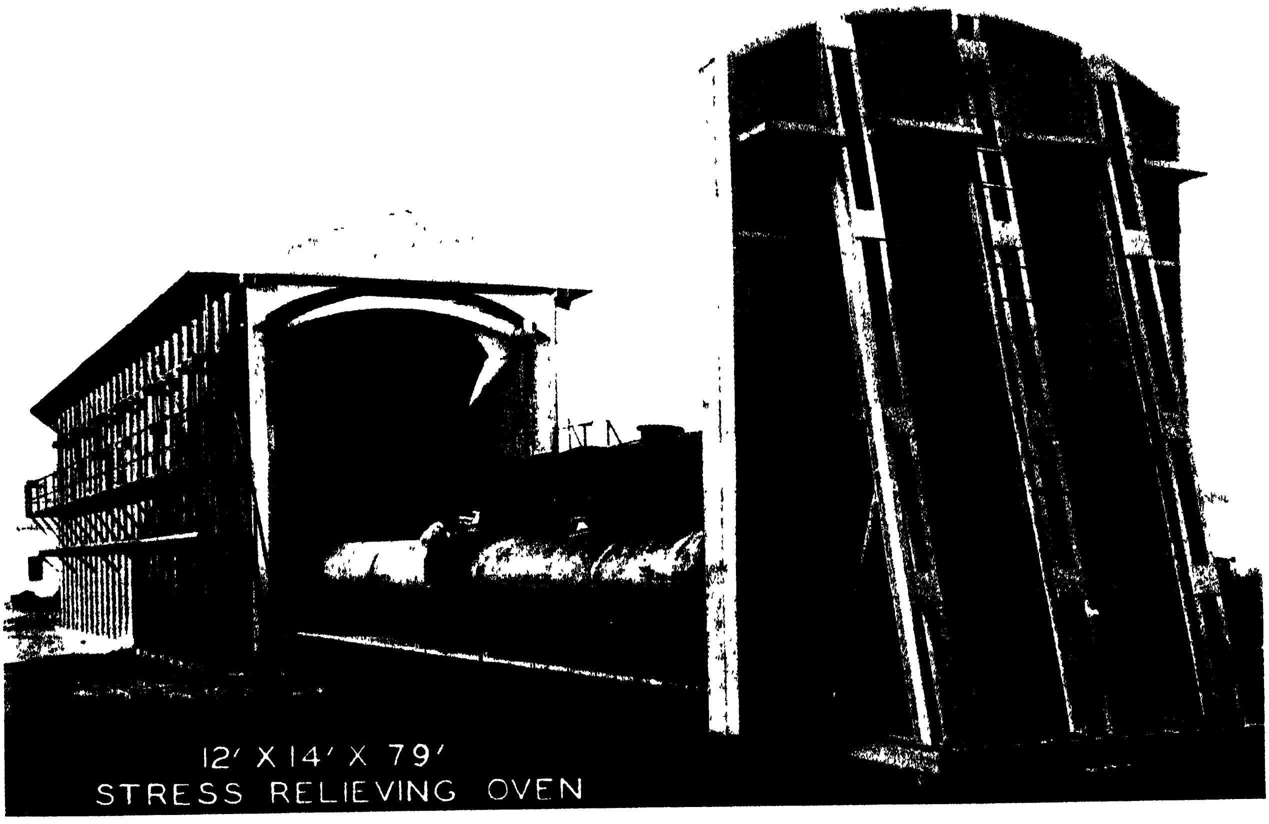

FIG. 3

tial vaporization under identical final conditions of temperature and pressure, the producing divisions of the oil industry overlooked these fundamental principles in their haste to obtain the maximum quantities of crude at any price.

Physical Chemical Laws Involved

Whenever a mixture of hydrocarbons is subjected to some definite temperature and pressure, one of three conditions may result:

(1) Total vaporization may take place, or in other words, conditions may be such that the mixture is at or above its dew-point, or point of initial condensation.

(2) Total condensation may be the result, in which event the mixture is at or below the point at which initial vaporization can take place.

(3) Partial vaporization or partial condensation may occur. This is usually the condition in flowing wells.

The degree to which vaporization or condensation will take place depends, of course, on the temperature and pressure of the system, as well as the composition of the original mixture. The method by which the vapour is released from the crude oil also has an effect on the percentage of the material vaporized. Lindsly [10, 1933] has described three different means of liberating gas from a crude oil-gas mixture which are, in substance, as follows:

(1) Flash vaporization occurs in one stage in a continuous-flow system under equilibrium conditions between vapour and liquid at a definite temperature and pressure. This type of operation is an ideal one for refinery operation, where the maximum amount of vaporization is desired. In this case the crude oil flows through a pipe still and flashes into a fractionating column.

(2) Differential vaporization takes place when the vapour is removed from its residual liquid as rapidly as it is evolved. To accomplish vaporization of this type requires a batch process in which either the temperature may gradually increase at constant pressure or the pressure may be slowly decreased at constant temperature. A derivation of the equation for differential vaporization is given by Walker, Lewis, and McAdams [17, 1927].

(3) A third type of separation is known as differential flash vaporization, in which a mixture of hydrocarbons may be flowed continuously through two or more separators in series. In each separator equilibrium flash vaporization takes place, the gas being removed from the upper section of each separator, while the residual oil flows from the lower section of each separator into the side of the next separator in the series until it finally discharges from the last separator into crude-oil storage. In this way the producer is able to approach differential vaporization, thereby retaining more of the stable gasoline fractions in the crude oil than would be possible with single-stage flash vaporization.

Hydrocarbons, when subjected to pressures above atmospheric, deviate quite widely from the so-called perfect gas and solution laws. Only in the past few years, however, has much interest been taken in this field, and the results obtained to date show that it is unsafe to make calculations based on the 'perfect' laws unless hydrocarbon systems, under atmospheric pressure or less, are being considered.

Flash Vaporization

Quantitative calculations on flash vaporization can be made, provided the equilibrium relationships between vapour and liquid are known. For low pressures Raoult's Law is usually accurate enough for engineering work. It may be expressed as follows:

$$\Pi Y_v = pX_L,$$

where Π = total pressure on the system,
Y_v = mol fraction of any component in the vapour,
p = vapour-pressure of the same component in the pure state,
X_L = mol fraction of the same component in the liquid.

If a system consists of one pure hydrocarbon existing in two phases, liquid and vapour, in equilibrium with each other, the total pressure would be equal to the vapour-pressure, and Y_v and X_L would each equal unity. With a mixture of hydrocarbons which are readily miscible in each other, the law will hold at low pressures, but under pressures above 50 or 100 lb. per sq. in. abs. the component parts of the mixture do not always exert their respective vapour-pressures characteristic of the pure state. This corrected vapour-pressure or escaping tendency is called the fugacity, and can be determined only by actual analyses of the vapour and liquid states which are in equilibrium with each other. Katz and Brown [7, 1933] show the relationship between the liquid and vapour states by Henry's Law:

$$Y_v = KX_L,$$

where Y_v = the mol fraction of any component in the vapour,
X_L the mol fraction of the same component in the liquid,
K an equilibrium constant dependent upon temperature, pressure, and nature of mixture. This K must be determined experimentally.

In calculating the percentage vaporization of any mixture which is being flashed at a definite temperature and pressure, a material balance should be made around the separator, the feed representing the input, and the vapour- and liquid-streams the output.

Let V = mol fraction vaporized,
$1-V$ = mol fraction liquefied.

On the basis of 1 mol (molecular weight) of feed, the balance for any one component will be:

$$\underset{\text{Input}}{1(X_f)} = \overbrace{\underset{\text{Vapour}}{V(Y_v)} + \underset{\text{Residual Liquid}}{(1-V)X_L}}^{\text{Output}}.$$

Since $Y_v = KX_L$,

$$1(X_f) = V(KX_L)+(1-V)X_L$$
$$X_f = X_L[1+V(K-1)].$$

For a two-component mixture an answer can be obtained by a straightforward algebraic solution, but for three components or more it is easier to assume different values for V, or the mol fraction vaporized, until the sum of the mol fractions each in the vapour and in the residual liquid add up to unity.

Need for Applied Research

The usual cut and try method has been employed to a large extent in the development of stage separation. In spite of the numerous variables which enter into such a problem, it is believed that the design of these systems for separating gas from oil can be placed on a more scientific basis than it is at present. Simplified methods [7, 1933;

9, 1927; 12, 1931] have been developed for estimating the percentage of vaporization of liquid fractions from true boiling-point data; however, these methods do not lend themselves so readily to mixtures consisting of gases and liquids. The problem, therefore, resolves itself into a laboratory study of such variables as temperature, pressure, number of stages, gas/oil ratio, and the physical properties of the gas and oil.

Experimental Work

Apparatus has recently been built in the Petroleum Engineering Laboratory at the University of Oklahoma for a quantitative study of stage separation under conditions of steady flow. Fig. 4 shows a diagrammatic sketch of the

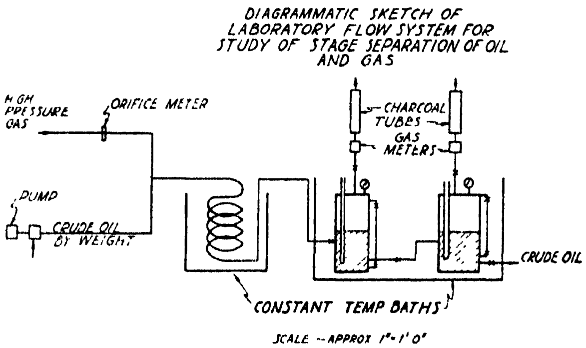

FIG. 4.

apparatus. A few data obtained to date on two-stage separation compare favourably with calculations which have been made on a hypothetical mixture of ethane and normal hexane, based on solubility constants published by Katz and Brown [7, 1933].

The first phase of the problem which is being investigated in this laboratory is that of determining the optimum ratio of pressures in a two-stage system which has atmospheric pressure for its second stage. Tonkawa crude oil saturated at 300 lb. per sq. in. abs. with dry natural gas consisting of 90% methane and 10% ethane has been found to yield a minimum gas/oil ratio of 64 cu. ft. per barrel when the pressure on the first stage is about 80 lb. per sq. in. abs. When higher pressures are used on the first stage, the gas/oil ratio on the low-stage builds up faster than the gas/oil ratio decreases on the high-stage, and as lower pressures are put on the first stage, the reverse phenomena appears, the total gas/oil ratio increasing above 64 cu. ft. The temperature is held constant at 120° F. during these runs.

Two-component System

Calculations have been made to determine the behaviour of a mixture consisting of 25 mol % ethane and 75 mol % hexane. These two components were chosen in view of the fact that the density of ethane compared favourably with that of the gas released from the crude, while hexane has about the same volatility as a number of commercial summer gasolines. The results have been plotted in Fig. 5. It is interesting to observe that the optimum pressure ratio between the high- and low-pressure stages is practically the same as the early data indicate for the Tonkawa crude oil-gas mixture.

Four-component Mixture

In any mixture consisting of two hydrocarbons, pressure and temperature fix the composition of the mixture so long as two phases are present, such as liquid and vapour. When three or more components are present in a two-phase system, pressure and temperature do not fix the composition of each component. Calculations have therefore been made on a mixture of gas and high-gravity crude oil. To simplify the calculations, this hypothetical mixture was

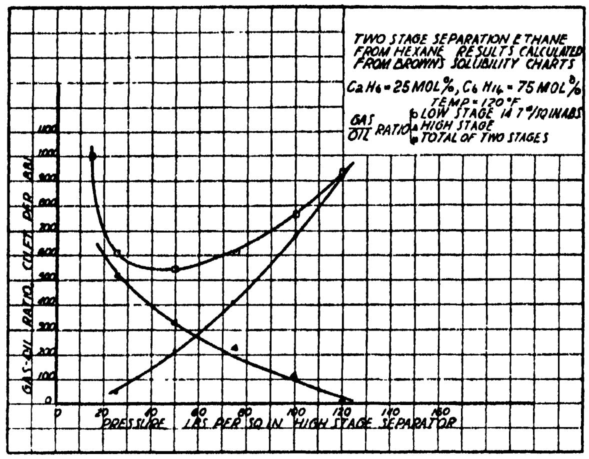

FIG. 5.

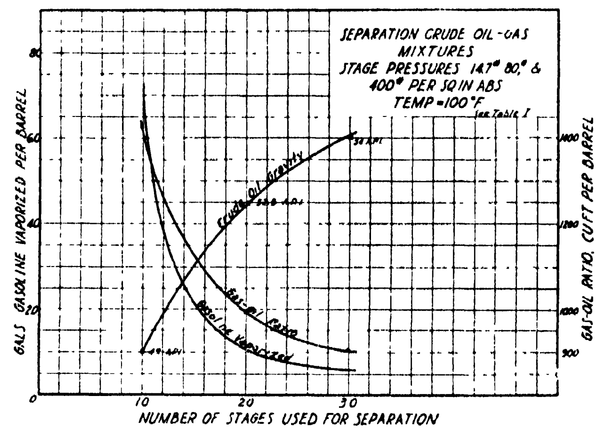

FIG. 6.

reduced to four key components—methane, normal butane, gasoline, and kerosine plus. The results of these calculations are shown in Table I and Fig. 6. It is easily seen that the advantage to be gained by additional stages beyond two separators falls off rapidly. For example, 7 gal. of gasoline are vaporized into the gas-stream for every barrel of crude produced when one stage is used. When two stages are employed, the gasoline drops to 1 gal., and for three stages about ½ gal. of gasoline is vaporized per barrel of crude oil produced. A curve similar in shape is found for the gas/oil ratios which decrease with an increasing number of stages. The gravity of the crude oil increases from 49 to 51·5°API. when going from one-stage to two-stage separation, while the increase is only from 52·5 to 54°API. when the stages are increased to three in number.

TABLE I

Summary of Calculated Results on Stage Separation of Crude Oil-gas Mixture Temperature = 100° F.

Physical Properties of the Crude Oil-gas Mixture

Feed component	Mol fraction	Mol weight	Sp. gr. of liquid, 60° F.	K = y/x at 100° F. 14·7 lb.	K = y/x at 100° F. 80 lb.	K = y/x at 100° F. 400 lb.	Cu. ft. liquid at 60° F. per lb. mol
C	0·50	16	0·430	200·0	40·5	11·50	0·587
NC	0·10	58	0·581	3·25	0·68	0·23	1·595
Gasoline . . .	0·20	110	0·738	0·30	0·055	0·02	2·38
Kerosine . . .	0·20	180	0·800	0·01	0·0018	0·0009	3·59

	Pressure lb. per sq. in. abs.	API. gravity of crude oil from final separator	Gas/oil ratio cu. ft. per bbl. of residual crude oil	Gal. gaso. vaporized per bbl. of residual crude oil	Molal composition of residual crude x_1	
Single flash	14·7	49·0°	1,426	7·33	C_1 . . .	0·0037
					NC_4 . . .	0·0408
					Gasoline . .	0·3770
					Kerosine . .	0·5785
						1·0000
Two-stage:						
First stage	80	..	953	0·937	C_1 . . .	0·0020
Second stage	14·7	52·5°	38	0·050	NC_4 . . .	0·1090
					Gasoline . .	0·4250
					Kerosine . .	0·4640
			991	0·987		1·0000
Two-stage:						
First stage	400	..	828	0·284	C_1 . . .	0·0025
Second stage	14·7	53·0°	143	0·820	NC_4 . . .	0·1167
					Gasoline . .	0·4230
					Kerosine . .	0·4578
			971	1·104		1·0000
Three-stage:						
First stage	400	..	804	0·2740	C_1 . . .	0·0020
Second stage	80	..	60·8	0·0612	NC_4 . . .	0·1445
Third stage	14·7	54·0°	40·4	0·2310	Gasoline . .	0·4170
					Kerosine . .	0·4365
				0·5662		1·0000

Three-stage Separation, 400, 80, and 14·7 lb. per square inch absolute, respectively, at 100° F.

First stage, 400 lb., 100° F. First trial, V = 0·48

	X_f	K	$K-1$	$V(K-1)$	$1+V(K-1)$	X_1	Y_v
C_1	0·5	11·50	10·50	5·04	6·04	0·0828	0·9530
C_4	0·1	0·23	−0·77	0·37	0·63	0·1588	0·0367
Gasoline . . .	0·2	0·02	− 0·98	0·47	0·53	0·3770	0·0075
Kerosine + . .	0·2	0·0009	−0·9991	0·4792	0·5208	0·3840	0·0003
						1·0026	0·9975

Second stage, 80 lb., 100° F.

	X_f	K	$K-1$	First trial, $V = 0·10$: $V(K-1)$	$1+V(K-1)$	X_1	Second trial, $V = 0·07$: $V(K-1)$	$1+V(K-1)$	X_1	Y_v
C_1	0·0828	40·5	39·5	3·95	4·95	0·0167	2·7650	3·7650	0·0220	0·8920
C_4	0·1588	0·68	−0·32	−0·032	0·968	0·1640	− 0·0224	0·9776	0·1625	0·1105
Gasoline . .	0·3760	0·055	−0·945	−0·0945	0·9155	0·4110	−0·0662	0·9338	0·4025	0·0220
Kerosine + .	0·3824	0·0018	−0·998	−0·0998	0·9002	0·4250	−0·0699	0·9301	0·4120	0·0007
						1·0167			0·9990	1·0252

Third stage, 14·7 lb., 100° F. First trial, V = 0·05

	X_f	K	$K-1$	$V(K-1)$	$1-V(K-1)$	X_1	Y_v
C_1	0·0220	200	199	9·95	10·9500	0·0020	0·4000
C_4	0·1625	325	2·25	0·1125	1·1250	0·1445	0·4700
Gasoline . . .	0·4025	0·3	−0·70	−0·0350	0·965	0·4170	0·1250
Kerosine + . .	0·4130	0·01	−0·99	−0·0495	0·9505	0·4340	0·0043
						0·9975	0·9993

TABLE II

Experimental Data—Two-stage Separation Crude Oil-gas Mixtures

Temperature 100° F.

Run no.	Separator pres. lb. per sq. in. abs. stage		Gas vol. cu. ft. 60° F., 14·2 lb. per. sq. in. abs.		Residual crude oil		Gas/oil ratio cu. ft. per bbl.		Gal. nat. gaso. per 1,000 cu. ft. of gas		Gal. nat. gaso. per bbl. of residual crude		
	High	Low	High	Low	Lb.	API.	High	Low	High	Low	High	Low	Both
1	39·0	14·2	9·73	0·835	37·08	..	75·2	6·46	1·35	1·737	0·103	0·0133	0·1163
2	125·7	14·2	1·455	1·875	16·13	41·5	39·0	44·5	0·913	2·92	0·0356	0·130	0·1656
3	98·2	14·2	1·45	0·795	8·5	41·45	48·7	26·3	0·638	4·51	0·031	0·1188	0·1498
4	74·2	14·2	3·244	1·19	21·5	41·4	42·5	15·8	1·915	3·10	0·0815	0·049	0·1305
5	40·2	14·2	4·8	0·555	24·25	41·47	56·0	6·45	1·513	4·16	0·085	0·0268	0·1118
						Temperature 120° F.							
6	164·2	14·2	3·01	5·35	40 0	40·47	21·6	38·4	0·585	2·88	0·01264	0·1106	0·12324
7	135·2	14·2	3·28	3·22	10·22	..	32·1	31·5	0·915	4·55	0·02935	0·1435	0·17285
8	114·2	14·2	2·93	2·55	23·3	41·4	36·0	31·3	0·80	2·48	0·0288	0·0777	0·1065
9	89·2	14·2	3·96	1·98	27 5	41·6	42·7	21·4	1·0	3·68	0·0427	0·07875	0·12145
10	64·2	14·2	5·8	1·535	30·3	..	56·5	14·5	1·026	3·64	0·0580	0·05275	0·11075
11	41·0	14·2	2·175	0·3575	7·2	..	86·6	14·95	1·84	2·93	0·1594	0·04375	0·20315
12	39·2	14·2	5·89	0·724	30·7	41·8	57·0	5·5	1·35	4·35	0·0770	0·0239	0·1009
13	17·2	14·2	1·572	0·00145	3·0	..	144·0	..	3 35	..	0·482	..	0·482
14	102·2	14·2	2·385	1·378	16·98	..	40·3	23·3	0·993	5·0	0·0401	0·1165	0·1566
15	56·0	14·2	2·14	0·5375	12·3	41·37	50·0	12·55	1·385	5·5	0·0693	0·0625	0·1318
16	126·0	14·2	0·774	0·917	5·08	..	43·7	51·75	0·63	2·218	0·0275	0·1148	0·1423
						Temperature 140° F.							
17	99·2	14·2	1·83	1·142	11·2	40·1	46·8	29·3	0·937	2·765	0·0439	0·0810	0·1249
18	64·2	14·2	1·80	0·52	13·4	40·4	38·5	11·15	1·737	4·32	0·0668	0·0496	0·1164
19	139·2	14 2	0·776	0·679	7·6	40·9	29·3	25·7	1·33	6·10	0·0390	0·1567	0·1957
20	135·2	14·2	1·545	2·07	13·58	41·63	32·0	45·0	1·196	5·08	0·0382	0·2290	0·2672
21	106·0	14·2	2·42	1·80	16·78	41·75	42·70	32·4	1·405	4·63	0·0600	0·1500	0·2100
22	69·2	14·2	1·10	0·442	5·60	41·9	57·23	21·6	1·68	6·40	0·09625	0·1383	0·2346
23	69 2	14·2	1 01	0·237	5·03	41·9	54·00	18·5	1·29	5·86	0·0697	0·1085	0·1782
24	45·2	14·2	0·73	..	3·80	..	54·9	..	2·44	.	0·1340	..	..

Discussion of Results

Field Data. The producer is interested primarily in the gravity of his crude oil, since the price per barrel is usually determined by the API. gravity of the oil. It has been found that two-stage separation of crude oil in the Lucien, Oklahoma field, with 50 lb. per sq. in. abs. on the high-stage and 14·2 lb. per sq. in. abs. on the low-stage, provides a crude oil which has a gravity of 41° API. Flash vaporization directly from the well to atmospheric storage produces a 40° API. oil. It is necessary to evaporate 2·6% by volume of a barrel of the 41° API. oil in order to lower its gravity to 40° API. This represents a loss of 1·09 gal. of 82·5° API. gravity natural gasoline. If a well in this particular field should not be making as much production as allowable, it is easily seen that the increase in production would amount to 2·66% over and above the amount produced by the flow of oil directly to storage. Evaporation tests on the 41 and 40° API. oils show that the rate of shrinkage in volume amounts to substantially the same for each oil, indicating that the retention of the 1·09 gal. of 82·5° API. natural gasoline by the 41° API. oil does not make this higher gravity crude any more volatile than the 40° API. crude, which no doubt retains more of the butanes and lighter hydrocarbons. It can be shown by calculations based on the solubilities of the various hydrocarbons that the single flash causes a retention of higher percentages of the methane and ethane in the crude than with two or more successive flashes. In other words, the stage separation results in a certain degree of stabilization of the residual crude oil.

Laboratory Results. The original data are included in Table II. The gas-oil ratios for the runs which were made in the laboratory proved to be so low that the effect on the gravity of the crude oil was not enough to offset experimental errors in recording the gravity. In Figs. 7, 8, and 9

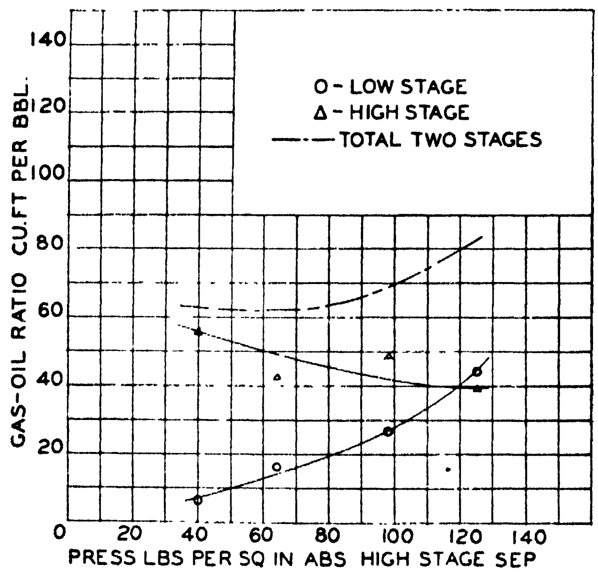

FIG. 7. Two-stage separation of crude oil-gas mixtures. Gas/oil ratios *v.* pressure on high-pressure separator. Temp. = 100° F. Low-stage = 14·2 lb. per sq. in. abs.

the gas-oil ratios are shown for the three temperatures 100° F., 120° F., and 140° F., respectively. The data for the 120° F. runs were more complete, and therefore the

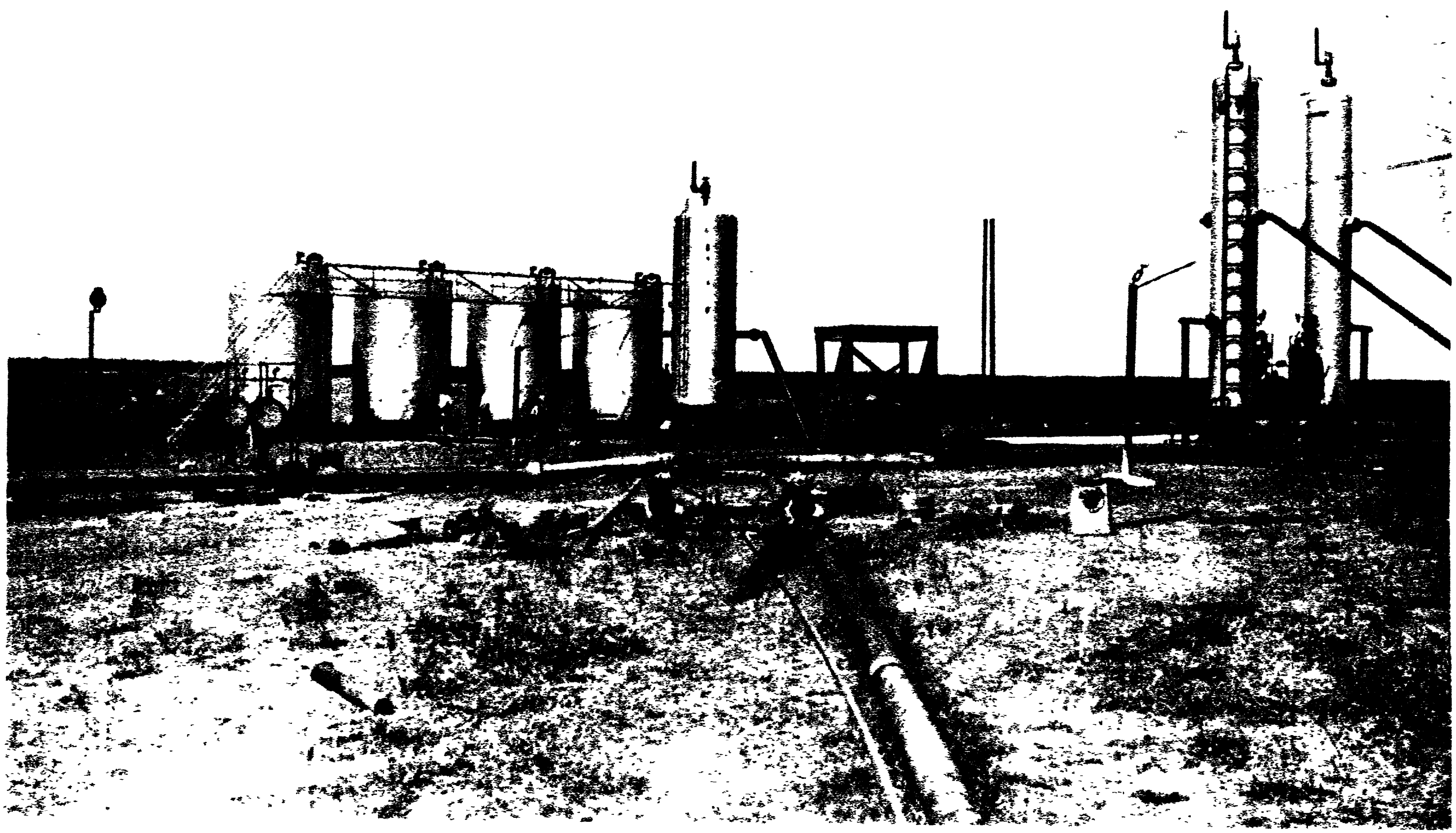

FIG. 10. Multi-stage separation plant

curves showing the gas/oil ratios for each stage are much better defined than the ones for the 100 and 140° F. runs. The most interesting conclusion which can be drawn from these curves is that there is an optimum ratio of pressures

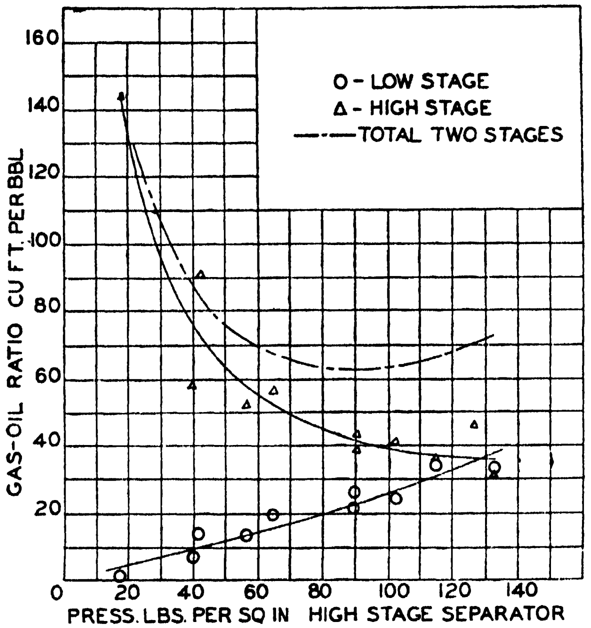

FIG. 8. Two-stage separation crude oil-gas mixtures. Gas/oil ratios v. pressure on high-stage separator. Temp. = 120° F. Low-stage = 14 2 lb. per sq. in. abs

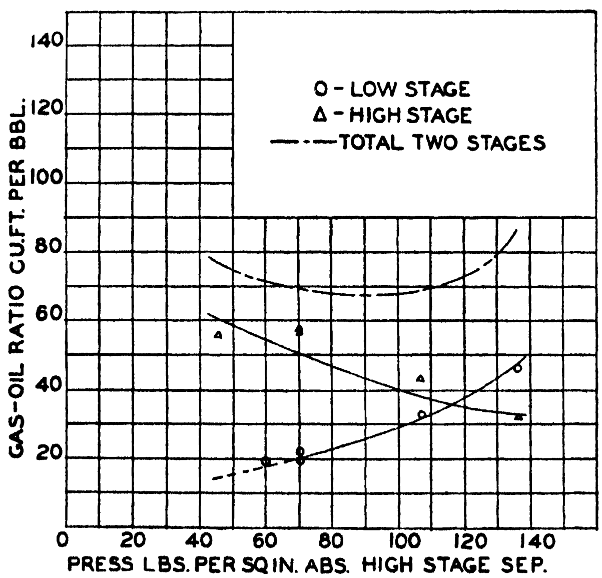

FIG. 9. Two-stage separation of crude oil-gas mixtures. Gas/oil ratios v. pressure on high-stage separator. Temp. = 140° F. Low-stage = 14·2 lb. per sq. in. abs.

between the high- and low-stage of about 5 to 1. If the pressure on the high-stage is too high, an excess of gas is held in solution and in turn released when the oil goes to the low-stage separator. If the pressure on the high-stage is too low, too much gas is vaporized from the high-stage separator, and the low-stage separator does not do its share of the work.

Importance of Stage Separation to the Manufacture of Natural Gasoline

The argument might naturally arise that stage separation of crude oil-gas mixtures will eliminate the necessity of natural-gasoline plants to a large extent. A thorough study of the problem, however, reveals the fact that the gasoline plants will still be needed even though stage separation may cause the retention of some of the natural-gasoline constituents in the crude oil. Since the oil-producing and natural-gasoline divisions must work together for the greatest economy possible for the industry as a whole, stage separation will eventually find its place as a link between the oil- or gas-well and the natural-gasoline plant.

Where extremely high rock-pressures exist, it is possible through stage separation to effect the condensation of high-gravity crude oils from the vapour state by the lowering of the pressure. Such a phenomenon is known as retrograde condensation, and is the reverse of what one would usually expect through a reduction in pressure. In this high-pressure region, above the critical pressure of the mixture, the vapour state acts somewhat like a liquid in its properties. In fact, it has been shown [8, 1934] that the vapour state is sometimes richer in the less volatile constituent than the liquid with which it is in equilibrium. Fig. 10 shows a stage hook-up at a recently discovered well near Moore, Oklahoma, where 2,000 bbl. of 64° API. condensate is being recovered from 25 million cu. ft. of gas. The bottom-hole pressure of the well is approximately 3,000 lb. per sq. in. abs., the two high-pressure separators in the right foreground are operating at 1,200 lb. per sq. in., the separator in the centre of the picture has 40 to 50 lb. pressure on it, and the four storage tanks are held near atmospheric pressure. Without stage separation it would not be possible to accomplish the results which are being attained at this well.

Early in the life of any oilfield the gasoline manufacturer is generally forced to speed up his construction activities in order to process the large volumes of gas that usually are produced from new wells. With the adoption of stage separation, higher available back-pressures will be made possible for the gathering of the gas into the lines which supply the gasoline plants. With these higher back-pressures it will be possible to bring the gas into the plants with smaller lines; and in addition to this, the investment in compressor equipment can be postponed until the back-pressures in the separators fall to a point where it will be no longer possible for the gas to reach the absorbers under sufficient pressure for economical operation. As soon as the back-pressures have fallen to the point where compressors and vacuum pumps are necessary, the gasoline plants would operate under the same conditions as they usually do in settled fields.

The next question which arises is that of processing the vapours which are released from the atmospheric storage tanks during the flush-production period. To handle these vapours would, of course, require not only the installation of compressor equipment, but also a low-pressure gathering system to bring the gas into the plant under vacuum. It is probable that this small volume of low-pressure gas would have to be released into the air for several years, or at least until the flush-production period had come to a close.

Entrainment of Crude-oil Mist

With stage separation the gasoline plant is assured of cleaner gas, i.e. less crude-oil mist will escape from the

high-pressure separators than from low-pressure or atmospheric tanks, which used to receive the crude oil-gas mixture direct from the well.

Entrainment of crude oil represents not only a total loss to the oil producer, but a nuisance to the natural-gasoline manufacturer, who has either to drain the oil from his gas-gathering lines or suffer a loss of efficiency in his absorption and distillation equipment, as the result of the contamination of the absorption oil. To keep the absorption oil free of crude oil requires a continuous re-run vacuum still from which the crude oil can be removed at the base. Just as entrainment is often the limiting factor in the design of bubble-cap towers, so is it gradually being realized that the mechanical carrying of crude-oil mist from separators is also of equal importance in the handling of flowing wells. It is probable that most of the gas-oil separators sold in the near future will carry with them certain guarantees in regard to entrainment losses.

Experimental Work

Since the charcoal test has become a standard one for making determinations of the natural-gasoline content of various gases, this method of testing was used in order to

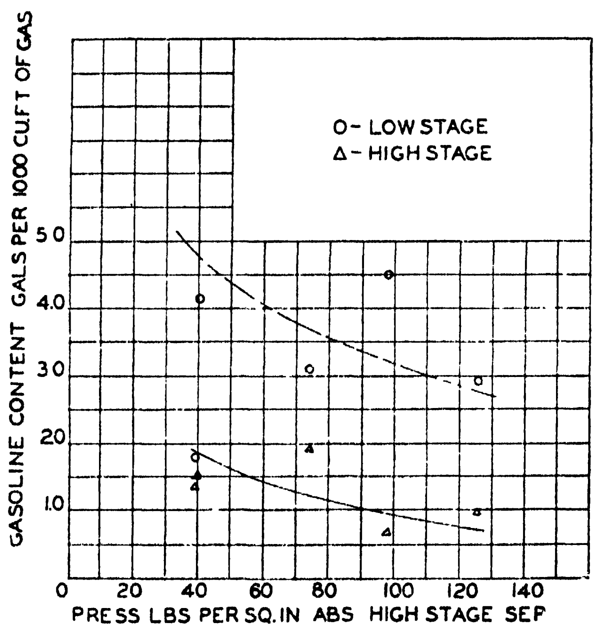

FIG. 11. Two-stage separation of crude oil-gas mixtures. Natural gasoline content *v.* pressure on high-stage separator. Temp. 100° F. Low-stage = 14·2 lb. per sq. in. abs.

find out the relative richness of the gas-streams from the two separators. Satisfactory and consistent results were obtained on the gas samples from the high-stage, but with the richer vapours from the atmospheric separator the data are somewhat scattered. The more complete set of data for the 120° F. runs shows that there is a definite decrease in gasoline content for each stage as the pressure on the high-stage is increased. The same trend holds true for the 100 and 140° F. runs, although not so well defined for the vapours from the low-pressure separator. Figs. 11, 12, and 13 present these data, showing the relationship between the gasoline content and the pressure on the high-stage separator.

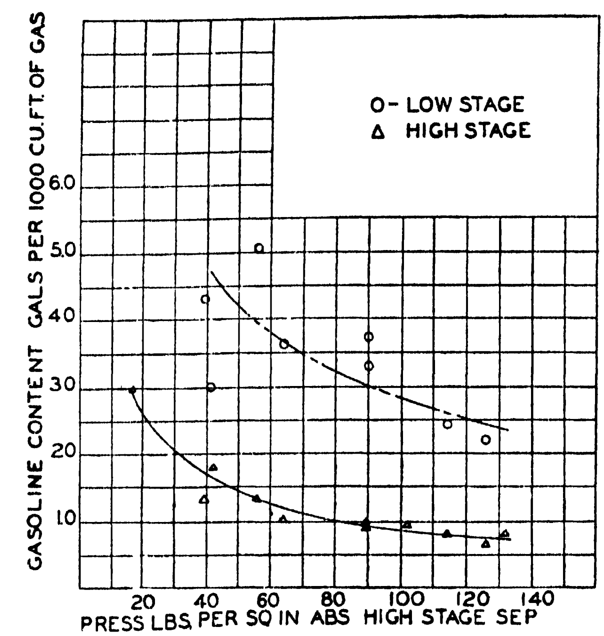

FIG. 12. Two-stage separation of crude oil-gas mixtures. Natural gasoline content *v.* pressure on high-stage separator. Temp. 120° F. Low-stage = 14 2 lb. per sq. in. abs.

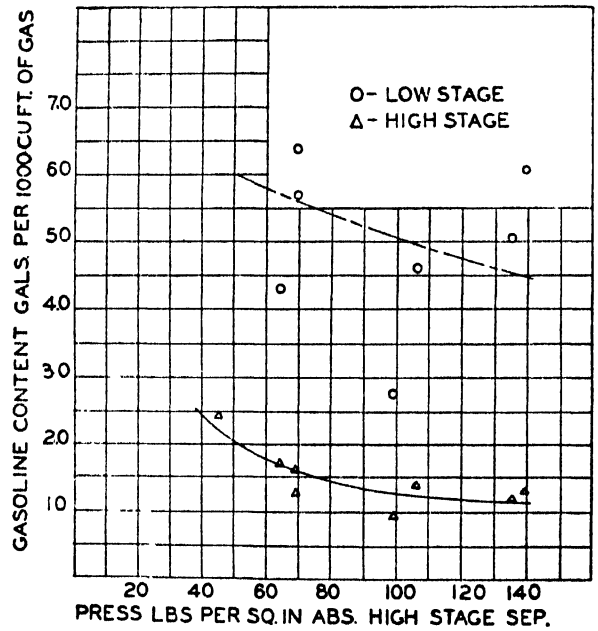

FIG. 13. Two-stage separation of crude oil-gas mixtures. Natural gasoline content *v.* pressure on high-stage separator. Temp. 140° F. Low-stage = 14·2 lb. per sq. in. abs.

Gasoline Production per Barrel of Crude Oil

By taking the product of the gasoline content and the gas-oil ratio, the number of gallons of natural gasoline per barrel of crude oil is obtained. These results are given in Fig. 14, and show that there is an optimum ratio of separator pressures quite similar to the one best suited for the obtaining of a low gas/oil ratio. The gas volumes from the 100° F. runs were so low that the data were not satisfactory. The gasoline per barrel of crude should run lower for 100° F. than for 120° F. That the gasoline content should

increase geometrically with rising temperature is shown by the vapour-pressure curve (Fig. 15) of the Tonkawa (northern Oklahoma) crude oil, which was used in this experimental work.

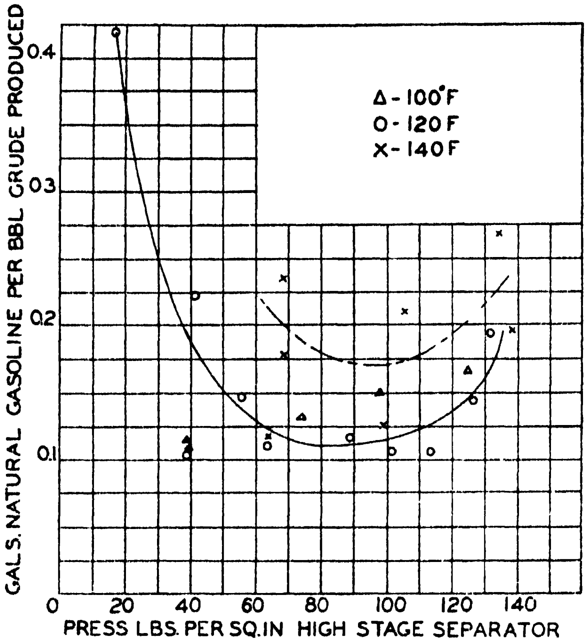

FIG. 14. Two-stage separation of crude oil-gas mixtures. Natural gasoline per bbl. of residual crude from both stages. Low-stage = 14·2 lb. per sq. in. abs.

Conclusions

The use of stage separation for crude oil-gas mixtures has witnessed a rapid growth during the past 10 years. Stage separation has made it possible for the oil producer to increase the API. gravity of his crude oil without appreciably increasing the evaporation losses in storage. The natural-gasoline manufacturer has been able to process the gas through smaller high-pressure lines and to postpone the investment in compressor equipment.

There is need for further applied research, in which a quantitative study of such factors as temperature, pressure, gas/oil ratio, and physical properties of the oil and gas should be made, thereby making it possible to design stage-

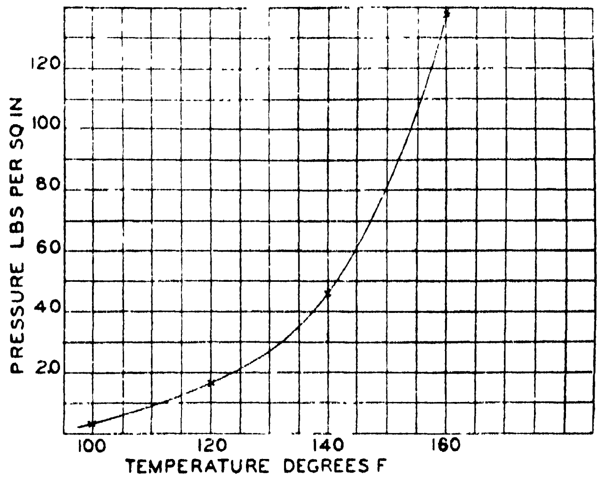

FIG. 15. Vapour-pressure curve. Tonkawa (Oklahoma) crude oil.

separation systems on a more scientific basis. The full value of this type of differential flash vaporization will not be fully realized until such an investigation has been completed.

Acknowledgement

The author wishes to express his appreciation to the *Oil Weekly Magazine* and to the Natural Gasoline Association of America for their generosity in releasing some of their recent publications which contain original data on stage separation; and to Professor W. F. Cloud, who cooperated in the securing of experimental data in the laboratory. The *Oil Weekly* articles on stage separation appeared on 15 and 22 July 1935, and the Natural Gasoline Association paper was published by the *Oil and Gas Journal*, 2 May 1935.

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CHEMICAL DEMULSIFICATION OF CRUDE PETROLEUM

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THE chemistry of emulsions and emulsification, which, of course, includes the chemistry of demulsification, represents a division of colloidal chemistry.

One of the most important applications of demulsification is in the recovery of dehydrated or 'clean' or 'dry' crude petroleum oil from 'wet' or 'cut' or emulsified crude oil. Almost all cut oil is produced from subterranean strata which, in addition to oil, also produce water or brine. In rarer cases, the water present in petroleum as produced comes from strata other than the oil-bearing formations. In substantially every case the oil and water are raised to the surface with rather violent agitation. Emulsification takes place when two mutually insoluble liquids are subjected to agitation in the presence of an emulsifying agent. If the emulsifying agent is water-soluble, or preferentially water-wettable, one obtains the oil-in-water type of emulsion. If the emulsifying agent is soluble in oil, or preferentially wetted by oil, the water-in-oil type of emulsion is produced [3, 1932; 6, 1921; 16, 1929; 26, 1914]. Pickering [30, 1910; 31, 1907], Briggs and Schmidt [7, 1915], and Schlaepfer [35, 1918] investigated finely divided solids as emulsifiers. These investigations are of primary importance, not necessarily because finely divided solids occur so frequently as emulsifiers, but because emulsifiers, particularly those which appear to be non-polar when dispersed in oil, may act in a manner very similar to the action of finely divided solids in stabilizing emulsions. It is perfectly evident that the conditions surrounding the production of crude oil are very likely to produce emulsions if an emulsifying agent happens to be present. Water-soluble emulsifying agents are very rarely present, and thus naturally occurring emulsions of crude oil-in-water are very infrequently found. The occurrence and amount of such naturally occurring crude oil-in-water emulsions are so insignificant that they will be ignored in the present discussion except when specific reference is made to them.

'Crude oil emulsions' is intended herein to refer to the water-in-oil type. In many crude oils there are present one or more emulsifying agents. The character of these emulsifying agents may vary. In some instances they may be asphaltic material; in other instances they may be asphaltic material adsorbed on finely divided sand or silt. In other instances the emulsifying agent may represent asphaltic material or the like adsorbed on paraffin. Beyond question, in those petroleum oils which have present any marked amount of an effective emulsifying agent, crude oil emulsions can be expected, because there is generally present another liquid insoluble in the oil, that is, the naturally occurring water or brine; and these two mutually insoluble liquids, in the presence of the naturally occurring emulsifying agent, are subjected to violent agitation in raising the fluid from the bottom of a well to the surface.

The daily production of crude oil in the United States has varied during the last several years within the range of approximately 2 million barrels to 3½ million barrels, of 42 gal. each. Estimates of the proportion of oil which is in the emulsified state as it comes from the wells vary from approximately 20% to approximately 35% of the above total. It might be assumed with a reasonable degree of accuracy that approximately one-fourth of the crude oil produced in the United States is emulsified. The demulsification of this oil is accomplished almost exclusively by the use of either one of two processes, or a combination of the two, namely, the 'chemical process' and the 'electrical process'. It is quite likely that the amount of oil dehydrated daily by these two processes is approximately equal in amount. Based on this assumption, it would seem that the dehydration of crude oil in the United States by the use of chemical demulsifying agents involves the recovery of approximately ½ million barrels of oil daily, at the present time. The conditions and problems surrounding the production of cut oil in the oilfields of the United States, and various other pertinent data, have been discussed by Dow [10, 1926].

Crude oil emulsions of the same general type as those referred to above occur in many other oil-producing sections of the world, e.g. South America, Roumania, Mexico, &c.

Historical

The history and development of the chemical method for the demulsification of crude oil emulsions can be divided into four rather distinct stages of development. This dissertation does not contemplate the discussion of the recovery of crude oil from petroleum emulsions by means of electrical dehydration, that phase of the subject being discussed elsewhere [39, 1937]. The electrical dehydration process developed simultaneously with the chemical dehydration process. The background preceding the electrical dehydration process, therefore, is the same background which preceded the chemical dehydration process.

The pioneer in the chemical treatment of petroleum emulsions and the discoverer of the present most widely used chemical demulsification process, employed in many of the oilfields of the world, was the late William S. Barnickel. The usual method of treatment of emulsions in the earlier days prior to Barnickel was to heat the emulsified oil so as to sludge the emulsion, which was then drawn off, burned, or run into creeks, with consequent contamination. In some instances, when the emulsion could not be sludged, the well was simply closed or some other disposition was considered. The processes of Barnickel really represented suitable chemical methods of recovering valuable pipeline oil from emulsified oil, a valueless waste product, the disposal of which was expensive.

Barnickel first proposed the use of a metallic sulphate, such as ferrous sulphate, for 'breaking' oilfield emulsions. Although the use of ferrous sulphate never found very wide application and was soon replaced by a more effective type of demulsifying agent, yet it illustrated Barnickel's discovery, namely, that one could 'break' or separate oilfield emulsions by means of non-corrosive reagents, added in relatively small amounts. Prior to the time of Barnickel, this fact was unknown. Within a relatively short time Barnickel employed reagents which were characterized by having the properties of a water-softening reagent

[4, 1917]. With the availability of Barnickel's process, involving the use of reagents of the water-softening type, acting in a manner to soften the hard water in the emulsion, the oil-producing industry was placed in a position to cope with the problem of cut oil by means of a suitable and satisfactory chemical process. Barnickel's process obtained immediate recognition and use, and made reasonable progress, until a subsequent discovery was made by him, which in essence revolutionized chemical treatment of emulsified oil. This last-mentioned development was his discovery of the fact that modified fatty acids, in the form of free acids or in the form of salts or esters, were most advantageous reagents for treating petroleum emulsions [5, 1923].

The first stage in the development of chemical demulsifying agents was, of course, the development prior to Barnickel, and is characterized chiefly by the lack of any process which could be applied commercially. Barnickel, as has been stated, in the second stage of the development, proposed the use of a non-corrosive demulsifying agent in a relatively small proportion for breaking oilfield emulsions. The third and most important stage was the development of modified fatty acids. The fourth or current stage of the development has been devoted largely to the development of refinements in the modified fatty acid type of reagents. Development has been continued by others since the death of Barnickel, who have elaborated on the matters pointed out by him. They have investigated various types of modified fatty acids, and indicated different kinds or classes of modified fatty acids or similar materials which are best suited for the treatment of specific petroleum emulsions.

It may be well to indicate here the development which the art has reached. At the present time, 1 part of commercially available chemical demulsifying agent will recover, on the average, approximately 10,000 parts of clean or dry oil. The original oilfield emulsion may, for example, have been composed of 50% of water and 50% of oil. In order that 1 part of demulsifying agent shall recover 10,000 parts of dry oil, it is often necessary for the demulsifying agent to be contacted with 20,000 parts or even more of the emulsion. In many instances the emulsion separates or breaks at the temperature at which fluids are produced at the well head. In some instances some heat may be required. Not only do these demulsifying agents recover, on the average, ten thousand times their volume of crude oil, but in some instances 1 part of demulsifying agent will recover 20,000, 30,000, or even 100,000 parts of clean oil. The process of chemical demulsification requires relatively little supervision. The demulsifying agents must not only recover clean oil, but they must also be available in a suitable and convenient form. For instance, the available demulsifying agents are effective within the lower temperature ranges, are supplied in a convenient liquid form, their viscosity does not change widely with temperature, and they may be pumped, or metered in small quantities, even in relatively cold weather.

Theoretical Aspects of Chemical Demulsification

The chemistry of oilfield emulsions has in reality a threefold claim to a place in colloidal chemistry. First, the dispersed phase consists of droplets of varying sizes, sometimes (rarely) consisting of droplets so small that they actually come within the particle size range often referred to as the colloidal range. Second, practically all oilfield emulsions are stabilized by the presence of colloids, in the broadest sense of this term. Finally, the modern commercial oilfield demulsifying agents or their subsequent reaction products, which are used to break oilfield emulsions, have certain colloidal properties. Various phenomena accompanying the colloidal state may be looked for, when investigating oilfield emulsions and their chemical demulsification, in these three distinct directions: first, the particle size of the dispersed phase *per se*; second, the inherent characteristics of the emulsifying colloid itself; and last, certain colloidal aspects of the chemical demulsifying agent.

When an investigator surveys the older available literature in an effort to determine the rationale of chemical demulsification of crude oil, there is relatively little information which is genuinely helpful. Furthermore, the greater general interest in emulsions lies in their manufacture, rather than their destruction or resolution. Petroleum emulsions represent the water-in-oil type, in which the emulsifying agent or colloid is oil-soluble or oil-wettable. The 'solutions' of such emulsifiers may be termed organosols, in contradistinction to aquasols. There is a great wealth of information concerning colloidal aquasols, but much less, in proportion, concerning colloidal organosols, that is, colloidal sols where the colloid is dispersed in an organic vehicle, such as petroleum oil. As a result, much information must be obtained by analogy to a corresponding situation wherein an aquasol is concerned. Then, too, in many cases the data must be considered in reverse order, so that possibly what takes place when an emulsion breaks may be foreseen.

An investigator may be misled because of an inherent misconception in regard to the nature of colloids themselves. This misconception in regard to colloids themselves is one that has been fostered unconsciously in some of the older treatises on colloidal chemistry. Every one knows why the earlier conception of colloids and crystalloids, erroneously attributed to Graham [17, 1934], has been discarded. Developments which followed were such that great emphasis was placed upon particle size. It was usually stated in a rather routine manner that colloids represented particles, at least one dimension of which came within the colloidal range (that is, somewhere between the particle size where the ordinary high-grade microscope ceased to function and the particle size which represented several times the size of large molecules). The next development following the particle-size line of thought was generally concerned with a discussion of Stokes' Law, and indicated that the true colloids, especially when dispersed in a liquid, represented particles of such small size that gravity did not appreciably affect them. This was usually followed by a discussion of the Brownian movement. As a result, when the word 'colloid' or 'colloidal state' is mentioned, there appears in the minds of some persons a sol (solution) of colloidal particles which are within the colloidal range, and not affected greatly by gravity, but stabilized by the viscosity of the sol and the Brownian movement, and by dispersing agents. Perhaps this represents a colloid or colloidal sol *par excellence*. As a matter of fact, probably no such colloidal sol exists commercially. Such colloidal sol rarely exists commercially but only under the most carefully regulated laboratory conditions. Possibly this thought partially explains why the present modern concept of colloidal chemistry is not dependent primarily on the existence of such colloid *par excellence*. More than a decade ago investigators realized the limitations of the older concept of colloidal behaviour. For example, reference is made to the views

expressed by Loeb [24, 1924]. The stability of colloidal systems, and, for that matter, the stability of the emulsifying agents which cause the emulsions, is not due primarily to particle size in most instances, even though the particles come within the designated colloidal range, and is not necessarily due to Brownian movement or the like. It is due generally to adsorbed ions, electrolytes, or molecules; or to adsorption or binding of the dispersion phase; or else to the adsorption of another colloid which has this same power of adsorption or binding of the dispersion phase (protective colloid action).

The stability of the colloid in many cases is the result of adsorption, which phenomenon will be discussed subsequently. If preferred, colloidal stability may be considered as being due to the fact that the colloid *per se* has adsorbed certain ions, molecules, &c.; or that the colloid *per se* represents a nucleus plus certain adsorbed ions, molecules, bound dispersion phase, &c. Thus the term 'colloid' may refer to the colloidal micelle with its double layer, &c., or else to the colloidal micelle with its bound dispersion phase, &c., or to a combination of the two. It might not be too much to say that the emulsion chemist is not interested in colloidal chemistry broadly so much as he is interested in the chemistry of adsorption.

Robertson [34, 1910], Newman [26, 1914], Briggs and Schmidt [8, 1915], Clowes [9, 1914], and Parsons and Wilson [28, 1921] have discussed inversion of emulsions. Briefly stated, if a water-in-oil emulsion of the type found in oilfields is subjected to certain agencies or physical factors, possibly such as electrical tension, which would bring about an inversion of the emulsion, and which would convert it into the oil-in-water type, it would, at least theoretically, have to pass through an intermediate point at which there is either no emulsion at all, or else there is a balanced tendency to produce both types of emulsion. It so happens that only by the most careful regulation can both types of emulsion tend to be produced. This is the same as saying that if gravity, coalescence, and time be permitted to act on the emulsion at this stage, the emulsion will be resolved or separated into its component parts. This statement may be considered as axiomatic. Not only that, but Ayres [1, 1921] states, 'one of the most interesting and practical ways of bringing about coalescence is that of pitting against each other protective colloids of opposite types—the hydrophile against the hydrophobe'.

The conditions surrounding demulsification might be developed more readily if one first considers an emulsion produced by means of finely divided solids [6, 1921]. Finely divided materials which are water-wettable, such as finely pulverized sand, may produce an oil-in-water emulsion because the sand is preferentially wetted by water. Similarly, a carbon black which is preferentially wetted by oil may be employed to produce a water-in-oil emulsion. Now if certain forces are made to act upon a water-in-oil emulsion, which is stabilized by the presence of oil-wettable carbon black, so that the nature of the surface of the carbon black is changed, and its surface becomes water-wettable, then the emulsion should break. Assume for the moment that certain solid asphaltic or resinoid matter which represents the emulsifying agent present in the crude oil are extracted from a crude oil, and suppose that this 'asphaltic matter' or 'petroleum asphalt' is dissolved in a volatile solvent such as carbon bisulphide. If a needle were dipped into this solution and the solvent permitted to evaporate, the needle would then be coated with asphaltum which is not water-wettable. This needle could be made to float on water just as does an oiled needle. Suppose that this needle coated with asphaltum, instead of floating on distilled water, is in fact floating on water containing some soluble calcium salts and soluble magnesium salts, such as are almost invariably present in naturally occurring oilfield brines. Suppose that, while it is floating in this manner, there is introduced into the bottom of the beaker a trace of a material capable of softening water, such as a solution of sodium oleate. Subsequently, there is formed a water-insoluble colloidal suspension of calcium or magnesium oleate. Let it be assumed that this suspension of calcium or magnesium oleate, as produced under the specified conditions, is hydrated or at least water-wettable. Suppose further that it adsorbs at the available interfaces, including the interface between the asphaltum-coated needle and the water. If it adsorbs on the asphaltum coating surrounding the needle, and thus changes the nature of the surface, then, instead of being unwetted by water, it becomes wetted by water. This is true because the hydrated calcium oleate or hydrated magnesium oleate adsorbed on the asphaltum coating is water-wettable. Under these conditions the needle sinks to the bottom of the beaker.

Now, reverting to the water-in-oil emulsion stabilized by oil-wettable carbon black, assume that the water contains some calcium salts or magnesium salts, and that a hydrophile soap-like colloid is added, especially in oil-miscible form, such as disclosed by Ayres [2, 1923]. It can then be stated that it is really immaterial whether this hydrophile colloid passes into the water, because at the interface there may be produced water-wettable materials, which may adsorb on the particles of oil-wettable carbon black and convert them from particles which are oil-wettable into particles which are water-wettable. If the particles become water-wettable, then the emulsion would be expected to break, if coalescence and gravity are permitted to act, in view of what has been said previously. Now it is true that some petroleum emulsions may be stabilized by finely divided sand or paraffin particles on which there is adsorbed asphaltic material, so that for practical effect the action is the same as if there were present finely divided asphalt or finely divided carbon black. On the other hand, it is more likely that these emulsifying agents, the asphaltic materials, may be dissolved colloidally in the oil, and might be referred to as oleophile (lipophile) colloids; and that in them the equivalent in oil of the hydrophile colloid in water has been produced. The problem still remains fundamentally the same. What can be done to this oleophile colloid to change it into an 'oleophobe colloid'? An oleophobe colloid is one which is unwetted by oil, or is wetted at least preferentially by water, and thus is hydrophile at least to that extent. For the time being, this phase of the discussion must be dropped, because we must return to the general consideration of colloids, particularly aquasols, and reason by analogy as to how this result may best be obtained.

Colloids, or more properly colloidal sols, are divided into two classes. The one class is known as the hydrophile, lyophile, emulsoid, non-electrocratic, or reversible type. The other is known as the hydrophobe, lyophobe, suspensoid, electrocratic, or non-reversible type. It is true, indeed, that many colloidal sols partake of the properties of both of these types; or, more correctly stated, every electrocratic sol has to a certain degree the property of the non-electrocratic sols, and every non-electrocratic sol has to a certain extent the properties of the electrocratic sols. There is no

absolute line of demarcation. If the colloid which is responsible for the formation of the water-in-oil emulsion, that is, the oil-soluble, oil-dispersable, or preferentially oil-wettable colloid, happens to be electrocratic in character, the emulsion would be expected to break by adding to the oil certain materials which would directly affect the stabilizing electric charge and which would break the emulsion in the same manner as an electrocratic suspension of colloidal gold can be coagulated by means of an electrolyte. Briefly stated, the colloids present in crude oil are rarely affected in this particular manner, without at least certain other forces coming into play. The oil-soluble colloid (the oleophile colloid, as it has been designated) has to a large degree the same properties in oil as a hydrophile colloid (particularly if non-polar) has in water. It is possibly a little difficult to imagine a non-polar emulsifier in water, when it is considered that water itself is a polar liquid, at least from the standpoint of a physical chemist interested primarily in dissociation. A hydrocarbon oil, of course, may not be an absolutely non-dissociating liquid, but as compared with water it may be so contemplated. Considering a hydrocarbon oil as essentially non-dissociating, and as essentially non-polar, it becomes apparent that non-polar emulsifiers may be present in the oil, whereas it is difficult to find their exact counterpart in water solutions. On the other hand, sodium oleate and a water-soluble gum almost free from polar radicals might both represent hydrophile emulsifiers and yet, comparatively speaking, such gum might be much less polar than sodium oleate, although the difference is in degree and not in kind. Furthermore, it is not the polarity of the molecule alone that determines certain characteristic effects, so much as it is some action or force exerted between the electric moment and some other influence, as, for example, a secondary valency force. From this standpoint it can be readily seen why certain polarity-orientation effects (which might reach an optimum value in the case of a highly polar molecule oriented in a liquid such as water, whose molecules exert a 'secondary' valency force) might be reduced to an absolute minimum, or almost disappear in the case of some organic molecule in which the electric moment is almost zero, when this last-mentioned molecule is dispersed in a liquid, for instance, some hydrocarbon in which there is almost no 'secondary' valency force, or other equivalent force.

Every one knows how ineffective small amounts of electrolytes are when used in attempting to salt out glue or albumen from water. Furthermore, the effect of electric charges in oil dispersions is greatly minimized as compared with comparable conditions in an aqueous phase. There are certain substances, however, such as tannin, that change the nature of certain hydrophile or emulsoid colloids almost as readily as an electrolyte changes the character of a hydrophobe sol like colloidal gold. Reference is made to the discussion by Kruyt on dehydration by tannins [22, 1927]. In the case of an oil-in-water emulsion, stabilized by gelatin, and to which is added tannin, then under the proper conditions the emulsion would be expected to break, for the simple reason that the water-wettable or water-solvated gelatin is converted into a substance acting as if it were non-solvated and hydrophobe in character rather than hydrophile. This is a change akin to the change which would take place if water-wettable sand could be converted into oil-wettable carbon black. Sensitization is another possible factor, the discussion of which is beyond the scope of this brief article.

Herein lies the clue to which the emulsion chemist concerned with breaking oilfield emulsions must look for an explanatory suggestion as to how the modern demulsifying agents break water-in-oil emulsions. The system containing the oleophile asphaltic emulsifying agent represents a relationship analogous to the oil-in-water emulsion that contains hydrophile gelatin. Instead of adding tannin to resolve it, something else must be added. In a vast majority of cases this 'something else' is a modified fatty acid of the kind described by Barnickel [5, 1923].

The analogy to the action of tannin has already indicated how and why such materials would be expected to be effective if it were possible to do the same thing to the asphaltic emulsifying agents that tannin does to gelatin. The asphaltic materials present in crude oil are substantially chemically inert. They cannot be expected to combine chemically with something else, a demulsifying agent, to form a new product which, instead of being oleophile, is oleophobe in character. The most that could be expected to be done is to add to such crude oil emulsion a material which, like the asphaltic material, is drawn to the interface and adsorbed on the asphaltic material so as to render it oleophobe (hydrophile) instead of oleophile. It was previously pointed out how the oleophile surface of an asphaltum-coated needle might become oleophobe (hydrophile) due to the physical adsorption of certain precipitated water-insoluble hydrated water-wettable alkaline earth salts, which are present in amounts exceeding their saturation points. This offers a second clue, and indicates why Barnickel considered water-softening reagents as effective demulsifiers.

This being true, it can be readily seen why the emulsion chemist interested in breaking oilfield emulsions of the water-in-oil type is concerned primarily with adsorption. The problem confronting such a chemist is essentially one of introducing into the emulsion in relatively minute quantities a reagent which is attracted to the interface and which, either *per se* or after reaction with the hard water or brine present, even if the reagent is present in a concentration below that required to reach the saturation points of its hard-water reaction products, is adsorbed on certain oleophile emulsifying materials by a force akin to chemical attraction (as distinguished from purely physical adsorption) to render them oleophobe or water-wettable. As a result of this action, there is a tendency for the emulsion to invert and, under properly controlled conditions, to break or resolve. Since this is true, a brief discussion of adsorption from this particular viewpoint is relevant.

The Role of Adsorption in Emulsification and Demulsification

As stated previously, no single phase of colloid chemistry is so important to an investigator in the field of emulsification and demulsification as adsorption. The present knowledge of adsorption, which is not limited to emulsion chemistry by any means, is still in an unsatisfactory state. There are two principal reasons for this condition. The first is that every one is not agreed on the definition of adsorption; and the second is that a clear concept of the forces which bring about adsorption is only being obtained slowly. This view is stated very briefly in *Chemical Engineers' Handbook* [29, 1934].

In an emulsion the emulsifying colloid (whether it be a finely divided solid or a polar compound of the oriented type such as sodium oleate) is held in position, or, inversely,

acts as an emulsifier, due to adsorption. It is quite possible that chemical demulsifying agents, when added to petroleum emulsions, adsorb on the emulsifying matter or on the emulsifying films, sometimes referred to as encasements of matter, or the fissures or openings of the emulsifying films, and change their surface character from oleophile (hydrophobe) to a water-wettable oleophobe (hydrophile) surface. It might be stated, incidentally, that perhaps these demulsifying agents do not adsorb as such, but probably adsorb in the form of 'nascent' highly colloidal hydrated calcium or magnesium salts.

These being the facts, it can be readily understood why the modern demulsifying agents for water-in-oil emulsions are materials which either as such or in the form of their alkaline earth salts are highly adsorbable. Ostwald [27, 1922] said that 'we may regard adsorption as that change in concentration which colloids and other dispersed systems suffer at the surfaces where they come in contact with other bodies'.

Adsorption is not limited to colloids. Ions are adsorbed as well. Many ordinary hydrophobe type colloids owe their stability primarily to adsorbed ions or the equivalent, and it is also true that these same factors are responsible in part for the stability of the hydrophile type colloid. Thus, in contemplating adsorption, the forces involved in adsorption must be considered.

Consider ordinary chemical combination. There is a primary valency which is represented by those manifestations of chemical affinity, which enable the combining capacity of elements to be expressed in terms of various atoms or their equivalents. It may be possible to assume that when this primary valency is satisfied the combining power of the resultant product has disappeared. Recent subatomic studies are succeeding in resolving valency into the fundamental electric forces responsible for it. The work of Bohr, Lewis, Langmuir, Hardy, Harkins, and many other investigators is too well known to require comment in this article. It is recognized that there is an auxiliary or secondary valency which represents the manifestations of residual chemical affinity, and which is able to bring about stable union of molecules, as though the molecules were themselves only radicals or ions, but able to exist also as independent units [25, 1927]. The modern concept of valency, even in regard to the primary valency entering into the chemical combination of atoms to form molecules, is divided at least into the classification of electrovalency and covalency. Whatever the concept of valency may be, it becomes evident that the consideration of a 'saturated' valency within a crystal must of necessity involve an unsaturated or 'active' valency on the outside or outermost layer of atoms in the crystal or particle of matter. This being true, it can readily be seen why adsorption which takes place at interfaces may be positive or negative. Certainly under carefully regulated conditions there is an adsorption of a monomolecular layer arranged or oriented so that this adsorbed monomolecular layer tends to offset or neutralize the surface unsaturation of the crystal or of the liquid, such as water, on which the film of adsorbed material happens to be present. This is especially true when the adsorbed material present in such monomolecular layer is polar and can orient itself so that the polarity effect tends to offset the effect of the unsaturated outer layer of the material on which it is adsorbed. Reference is made to the investigations of Hardy [19, 1912–13], Harkins [20, 1917–26], Langmuir [23, 1917–25], and of Finkle, Draper, and Hildebrand [15, 1923]. There is no intention to deny the possibility, under defined conditions, of physical adsorption, as differentiated from chemical adsorption or so-called 'activated' adsorption. Indeed, it is possible that demulsifying agents, characterized purely by water-softening characteristics, and used in a manner so as to make the assumption that water-softening occurs a reasonable one, may function due to physical adsorption, whereas the modern demulsifiers, even though having water-softening characteristics, may be employed effectively under conditions such that a water-softening action is not readily apparent, and thus indicate 'activated' adsorption.

Oilfield emulsions involve adsorption in at least two very important ways. In the first place, the emulsifying colloid is adsorbed; and in the second place, the chemical demulsifying agent (as such, or more probably in the form of its hydrated alkaline earth salt) is adsorbed on the emulsifying agent. Perhaps it is true that the demulsifying agent or its alkaline earth salt is adsorbed on the emulsifying agent in the form of a monomolecular film as suggested by Langmuir, Harkins, and others. It is also known that very finely divided solids may act as emulsifying agents. Emulsifying films prepared from such finely divided solids cannot be monomolecular. Furthermore, it is known that emulsions can be prepared in which the skin of the emulsifying agent is visible to the naked eye [21, 1934]. Sometimes when oilfield emulsions break, there appears at the boundary surface between the oil and the water coarse emulsion which is characterized by having films visible to the naked eye. Therefore, the theory of adsorption proposed by Langmuir and others, and which involves the assumption that the forces acting in adsorption are of nearly the same kind as the forces which cause chemical combination, may be most significant in explaining the adsorption of the chemical demulsifying agent or its hydrated alkaline earth salt on the emulsifying film. There is reasonable doubt, however, as to whether the emulsifying film composed of the naturally occurring emulsifying substances, such as asphaltic material, resinous material, and the like, in the crude oil (i.e. isocolloids) is necessarily of monomolecular proportions. This fact directs attention to the Eucken- [14, 1914] Polanyi [32, 1914-20] theory that the adsorbed material may consist of a polymolecular layer. There is a marked distinction, probably, between the material which is adsorbed at the water-oil interface (the emulsifying agent, which may be asphaltic material in the case of petroleum emulsions) and the chemical reagent which adsorbs on the emulsifying agent. The emulsifying agent in naturally occurring petroleum emulsions may be substantially non-polar, whereas the ordinary commercial demulsifying agent or its alkaline earth salt which adsorbs on the emulsifying agent is invariably polar.

This brings us to the definition of polarity. Ware [40, 1930] says, 'A molecule like NaF is said to be polar because the two essential parts are electrically unlike.' A polar compound, according to Hackh [18, 1929], may be 'any electrolyte or any compound that may ionize when dissolved or fused. In general all inorganic acids, bases, and salts belong to this group in which the atoms are supposed to be held in electrostatic union.' Likewise, a non-polar compound may be 'any non-electrolyte—in general, an organic compound the atoms of which are supposed to be held in electromagnetic union by sharing a common pair of electrons'.

The following somewhat extensive discussion of polarity is of eminently practical interest because it involves those factors which ultimately determine, at least to a large extent,

the composition of the modern demulsifying agent. This relationship will be discussed subsequently.

It is unfortunate that the word 'polar' is used in two different senses. It is also perhaps a bit confusing that for convenience in considering certain phases of demulsification, one may be forced to adopt a conception somewhere between these two ordinary conceptions. The definition of Hackh previously referred to is the definition of a physical chemist primarily interested in electrolytic dissociation. The term 'polar' as used by Gortner, Harkins, Rideal, and others is intended to refer to the fact that one portion of a molecule contains groupings which are soluble in water, and another portion of the same molecule contains groupings which are not soluble in water. The water-soluble groupings are polar groups. A molecule is considered as being polar because it is dipolar, or sometimes the molecule itself is referred to as a dipole. As stated by Smyth [37, 1931]:

> 'When two charges, $+e$ and $-e$, equal in size but opposite in sign, are separated by a very small distance d, they form an electric doublet or dipole, the magnitude of which is measured by its electric moment, $m = ed$. Substances, the molecules of which are supposed always to have electric moments, will be referred to as polar, while those possessing no permanent moments will be termed non-polar.'

From the standpoint of the colloid chemist, such materials as ethyl alcohol, acetone, &c., are essentially polar compounds, although from the standpoint of Hackh, above referred to, they are non-polar. In the actual consideration of certain demulsifiers, interest is primarily focused on certain molecules which are not only polar, but are also ionogenic. Consider the difference between the introduction of a chlorine atom into a naphthalene nucleus, thus forming a non-ionogenic compound, as compared with the introduction of an ionogenic sulphonic acid radical into a naphthalene nucleus. It is this latter type of compound, the ionogenic highly polar type, that ultimately requires the most careful consideration. Unfortunately, compounds having radicals susceptible to acetylation or other similar groups are not ordinarily considered as being ionogenic. Thus it becomes necessary to stretch the expression 'ionogenic' beyond its customary meaning, simply for the purpose of convenience, to cover this type of compound. At this point it therefore becomes clear that the writer is forced to treat polarity in a somewhat mixed sense, as related to its two ordinary meanings. Otherwise the problems presented by polarity would have to be resolved further into the problem of polarity in its orthodox colloidal sense, and also into the problem of ionization as it is considered by physical chemists. The justification of this adopted procedure rests in part on the fact that too many substances, particularly organic substances, are polar in the orthodox colloidal sense. In other words, even when the value of the electrical moment approaches zero, and may be almost insignificant, the molecule may still be considered as polar. Many of the phenomena surrounding polarity, such as orientation, for example, are not concerned with the value of the electrical moment alone, but rather with the result of a certain relationship existing between the electrical moment and some other force, such as a 'secondary' valency force. In this connexion, perhaps it is not the molecules of relatively low polarity that give such characteristic effects, but rather molecules which appear to be of relatively high polarity. For this reason, much that is said in regard to the effect of polarity in polar molecules, especially in regard to orientation, applies, perhaps most characteristically, to molecules of relatively high polarity, dispersed or oriented in 'polar' liquids capable of exerting 'secondary' valency forces or their equivalent.

Investigation reveals that polar compounds are more likely to adsorb as a monomolecular layer, whereas the non-polar ones may, at least under certain specific conditions, adsorb as polymolecular layers. This fact always brings one back to the construction of the molecule itself.

The matter of polarity does not end here, but is stated perhaps more fundamentally in terms of electrostatic moments. Polarity is not a fundamental characteristic; interpretations as to the effect of polarity must be qualitative and not quantitative; and they are not absolutely mathematical. This is stated excellently by Ware [41, 1930]:

> 'It must be kept in mind that polarity is not a fundamental characteristic and therefore must be interpreted as representing a degree only.
>
> 'Small electrostatic moments are of very great importance in adsorption phenomena, and molecules whose ends have opposite characteristics are well suited to the process of orientation. This is particularly true when the molecule contains a polar group, as OH, COOH, CHO, NH_2, SCN, NO_2, (HSO_4, HSO_3), &c.'

The fact that polarity is not a fundamental characteristic, but rather a representation of chemical behaviour, is indicated by Smyth [36, 1931]:

> 'Polarity may occur, but ordinarily as an accompanying result rather than as a determining factor in chemical behavior. Although pronounced polarity is doubtless a factor in chemical behavior, a large portion of the polarities assigned by the various electronic theories of valency must be regarded not as a physical fact but merely as a pragmatic representation of chemical behavior.'

The conditions surrounding polarity also require further elucidation. Sodium oleate, which is called a 'polar' compound, may dissolve in water, which is also polar. Certain marked changes take place, particularly in the surface tension of the water. Suppose that sodium oleate could be dissolved in a non-polar liquid or in a liquid of relatively low polarity, such as carbon tetrachloride, or a white medicinal petroleum oil. Is sodium oleate just as polar in both such solvents? As has been stated previously, the use of the word 'colloid', in reference to a substance as such, is rather an improper use, but a convenient one. Similar looseness appears in various discussions of polarity. A substance is denoted as being polar. In many instances it is meant that the substance is polar when dissolved in water, or in a polar solvent, or that in such state of solution the substance orientates. Frequently polarity is meant to indicate the introduction of an ordinarily hydrophile group or atom into a hydrophobe body or residue, such as the introduction of the sulphonic group, $—SO_3H$, into a benzene residue, $C_6H_5—$; but even this is not an exact use, because in most instances such hydrophile groups are not only hydrophile, but also 'ionogenic', i.e. capable of forming ions. Thus, for matter of convenience, in considering emulsification and demulsification, one may consider polar compounds as large molecular weight colloidal bodies, having a large molecular-size hydrophobe residue, frequently of a hydrocarbon nature, and at least one ionogenic

(usually hydrophile) group or radical; but not necessarily including such combinations where the hydrophile group, or groups, is not, or are not, ionogenic. In this respect the word 'ionogenic', dealing in many instances with water-insoluble materials, may include not only those groups which are ionogenic in the ordinary sense, but also residues, radicals or groups which are salt-forming, or saponifiable or capable of acetylation.

Surfaces are characterized by possession of a surface tension, except perhaps in the cases of gases. The surface tension of solids is not particularly susceptible to investigation. In the case of emulsions, we are concerned with the surface tensions of two dissimilar liquids, or, more exactly, with the interfacial tension existing between these two liquids at their boundaries. The conception of surface tension as a surface skin is sometimes convenient but basically incorrect and often unsatisfactory. It is perhaps better to consider surface tension as resulting from an effort of the molecules to crowd inward.

Under such circumstances, some molecules must form the outer layer, and the outside of these outer molecules represent unsaturated valency forces. A change in the character or force of these outside unsaturated valency forces may basically change the inward crowding, at least of the immediate inside layers of the molecules. Hence, when adsorption takes place and the interfacial tension is lowered, it is because interfacial tension is primarily a phenomenon related to or indicated by unsaturated atomic or molecular forces akin to the forces which underlie chemical reaction.

The formation of an adsorbed film or the formation of 'adsorption compounds' under other circumstances, such as the formation of the Purple of Cassius, or, even better, the formation of a lake (dye-mordant complex), represents forces not primarily different from the forces of chemical combination. Even orthodox chemical compounds, such as oxonium compounds, or chelate compounds, may require the existence of a residual valency force to explain their apparent structure. Obviously, polar substances may adsorb more readily than non-polar substances; or, at least, when polar substances are adsorbed they go much further per unit of mass in satisfying or saturating the 'residual outside valencies'. Water has a surface tension of approximately 72 dynes per cm. This surface tension may be considered to represent certain chemical forces at work, forces which are residues of those which previously had brought about chemical combination between hydrogen and oxygen to produce water. These remaining forces are designated as residual outside valencies. When sodium oleate, a polar compound, is added to water in sufficient amount, the (static) surface tension drops to about 36 dynes per cm. It is reasonably certain that the sodium oleate is orientated in the surface so that the sodium atom is immersed in the water and the fatty hydrocarbon chain projects outwardly. These projections of the fatty chains then exert a force which counteracts the residual outside valencies, and the surface tension is reduced to only approximately one-half its former value. Finely divided solids, not being molecular in size, cannot undergo such molecular orientation, and likewise presumably cannot undergo equivalent molecular projection through an interfacial or a surface boundary. Of course, ions or molecules adsorbed on their surface may be polar. Therefore, if a finely divided solid, wettable by water, is shaken with water, even though it may act as an emulsifying agent, it does not lower the surface tension to any great extent; or, to put it another way, the finely divided solids which do not approach molecular size, do not particularly offset or counteract the residual outside valencies. What has been said in regard to finely divided solids appears to apply with equal force and effect to the majority of non-polar compounds, and especially in the case of non-polar compounds in relatively non-polar liquids. Subsequent investigation might reveal compounds which are strictly non-polar and of the perfectly symmetrical molecule type, which might still influence surface tension, so that it is possible and indeed probable that adsorption surface-tension changes are not invariably associated with polarity alone. Water has a surface of tension approximately 72 dynes per cm. Assume that an oily vehicle, for instance, white medicinal oil, has a surface tension of 36 dynes per cm. It is difficult to forecast what the interfacial tension between these two liquids will be. As an approximation, and only an approximation, it may be said that the interfacial tension will roughly represent the mathematical difference between the two surface tensions, or 36 dynes per cm. Suppose, however, that sodium oleate is added to the water so that the surface tension of the water is initially lowered to 36 dynes per cm., and that this soap solution is then contacted with the oil so that there is substantially no interfacial tension when measured in the ordinary manner. Under these conditions, so far as that particular interface goes, there is little or no remaining residual outside valency effect. There is little or no tendency to adsorb further or to form other adsorption compounds at the interface. The condition approaches incipient mixture of two mutually miscible liquids.

In the case of water-in-oil emulsions the continuous phase is oil. Oil, in the absence of any emulsifying agent, may have a surface tension of about 36 dynes per cm. or thereabouts. When an emulsifying agent of the kind naturally present in crude oil is added to such an oil free from emulsifying agents, there is a relatively small lowering in surface tension, perhaps from 36 dynes per cm. to 32 dynes per cm. or thereabouts. The lowering (if any) is comparable to the reduction in surface tension which occurs when a finely divided solid is added to water. This being true, an important generalization can be made, and one on which chemical demulsification is largely dependent. In water-in-oil emulsions of the type which ordinarily occurs in oilfields, the emulsifying agent present in the oil is of the non-polar oleophile (hydrophobe) type. As far as saturating outside residual valencies manifested by the interfacial tension is concerned, the effect produced by the naturally occurring emulsifying agent is comparable to the effect of finely divided insoluble solids in water. Therefore, notwithstanding the existence of a persistent emulsion, the residual unsaturated valencies, as manifested by the interfacial tension, still exist at approximately optimum values at the interface; and, therefore, there is attracted to the interface the added chemical demulsifying agent, if it is highly adsorbable. This agent, under proper conditions, converts the surface of the oleophile demulsifying agent into an adsorption compound, which latter compound is oleophobe (hydrophile) or at least water-wettable; and the tendency towards inversion sets in, which under the action of coalescence and gravity, and assuming sufficient time to act, permits the emulsion to break.

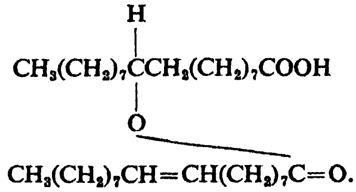
In the previous paragraph the significant expression, 'if it is highly adsorbable', has been used. Adsorption at the hydrophile-hydrophobe interface is effected not primarily by the polarity of the adsorbable substance in the broad

sense that NaF is polar, but it is in part and possibly primarily effected because the polarity that exists is due to the presence of one or more hydrophobe and hydrophile radicals in the molecule. This may be restated by saying that the polarity is due to a heterogeneous (hydrophile and hydrophobe) molecular differentiation. This statement, in regard to adsorption, is after all only a restatement of the well-known Langmuir and Harkins' theory of orientation of adsorbed films at interfaces.

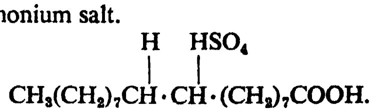
Other factors may enter into demulsification, but it is believed that the primary factors responsible for the effectiveness of the type of chemical demulsifying agent commercially used on crude oil emulsions is the explanation which has been given above. An excellent article by C. H. M. Roberts [33, 1932] deals with a résumé of emulsion theory, and its application in the chemical treatment of emulsions, in a general way. The theory of emulsions proposed by Roberts is an extension of the currently accepted adsorption-film theory in several important respects. The ideas that emulsifying films are necessarily due to colloids and that such films exist only on the external side of the water-oil interface are abandoned in favour of the concepts of emulsifying films consisting of ions and polar molecules, which films form on both sides of the interface. Roberts indicates that the principles of the theory point to the existence of, and necessity for determining, both the electrokinetic potentials and the interfacial tensions on both sides of an emulsion interface.

An important previous paragraph may now be substantially restated as follows: 'In water-in-oil emulsions of the type which ordinarily occurs in oilfields, the emulsifying material present in the substantially non-polar oil is of the non-polar oleophile (hydrophobe) type. As far as saturating or offsetting outside residual valencies manifested by the interfacial tension is concerned, the effect produced by the naturally occurring non-polar emulsifying material in non-polar oil is analogous to the effect of finely divided insoluble solids in water; and, therefore, notwithstanding the existence of a persistent emulsion, the residual unsaturated valencies (as manifested by the static interfacial tension) still exist at approximately optimum value at the interface. Thus there is attracted to the interface the added chemical demulsifying agent. This is especially true if the chemical demulsifying agent is colloidally dispersable in oil. Then, if the chemical demulsifying agent is further characterized by the presence of a (preferably ionogenic) hydrophile and hydrophobe radical or atom which orientates as such, or in the form of an alkaline earth salt, under proper conditions, then the outer surface of the hydrophobe emulsifying material, or at least that part of it in contact with the water of the emulsion, is converted into an adsorption compound, which latter compound is oleophobe (hydrophile) or at least water-wettable. The tendency towards inversion sets in, which, under the action of coalescence and gravity, and assuming sufficient time to act, permits the emulsion to break.'

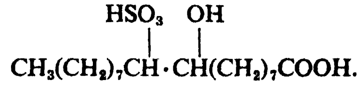
The modern demulsifying agent is based primarily on these principles, which were first applied by Barnickel, even though the rationale may not have been completely understood in 1919 [5, 1923]. Examples of such compounds are in universal use. Other types of reagents are represented by certain non-fatty sulphonic acids and their salts. As briefly illustrative of these various types of modern reagents employed for chemical demulsification of oilfield emulsions the following examples may be considered:



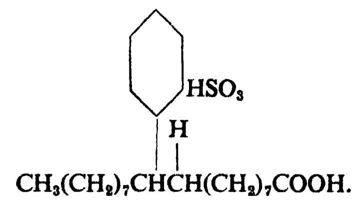
Oleilhydroxystearic acid: Used as such or as a salt, such as the ammonium salt.



Oleic acid hydrogen hydrogen-sulphate: Used in form of mono- or di-salt, such as monoammonium or diammonium salt.



Hydroxy-olei-sulphonic acid: Used as such or in the form of a salt, such as monoammonium or diammonium salt.



Benzene sulphostearic acid: Used as such or in the form of a mono- or di-salt, such as monoammonium salt or diammonium salt.

$$C_{20}H_{27}SO_3H \quad \text{and} \quad C_{24}H_{33}SO_3H.$$

Petroleum sulphonic acids: Used as such or in the form of salts, such as the ammonium salts. (Formulae are intended to be illustrative only.)

Although these examples show variety as to chemical composition, it is to be noted that they almost invariably present five features, in that:

(*a*) They give colloidal dispersions in oil, at least when very dilute, thus tending to adsorb at oil-water interfaces.

(*b*) They contain hydrophile and hydrophobe groups, radicals or residues, so that they not only adsorb at interfaces, but, either as such or else in the form of the corresponding alkaline earth salts, they orientate at the interface between the oil and the water.

(*c*) There is present a radical (or radicals) which, when combined with a calcium or a magnesium atom, will produce an insoluble salt if the concentration is great enough (water-softening effect); and the hydrated calcium or magnesium salts of these materials, as exemplified by the forms produced by precipitation in dilute solutions, are water-wettable even though water-insoluble.

(*d*) Into a hydrophobe group or radical there is introduced another group, radical or residue, which may be hydrophile or hydrophobe, but in any event it is ionogenic in the broad sense mentioned.

(*e*) In regard to those of the above compounds which happen to be modified fatty acids in the sense that the term was used by Barnickel [5, 1923], in comparison with sodium oleate or oleic acid, the following distinction is very marked: In oleic acid, or sodium oleate, there is a polar compound in which there are two nuclei or foci of polarity, as exemplified by 'secondary' valencies, and which are arranged terminally to each other; whereas, in the modified

fatty acids, or salts or esters thereof, there are at least three nuclei or foci of polarity (as exemplified by 'secondary' valencies) and they are not arranged terminally; at least one focus or nucleus being in a non-terminal position, and characterized, moreover, by being located in the hydrophobe (oleophile) residue. Our knowledge of various factors such as orientation of complex multipolar molecules at interfaces, the relationship of polarity and valence, &c., is still too meagre to evaluate the exact mechanism by which this offset 'secondary valency' or nucleus of polarity operates. Possibly the modern demulsifying agent acts by virtue of a peculiar orientation of multipolar molecules, so as to break oilfield emulsions so much more effectively than the older, simpler types of reagents, such as oleic acid or sodium oleate. In any event, we know that this is so true that the newer types, even at much higher cost, have completely superseded the old sodium oleate type.

Here perhaps is the sharpest practical differentiation between common water-softeners, satisfactory for use at a ratio of 1:1,000, which exhibit a measurable amount of water-softening, and modified fatty acids which act at a ratio of 1:10,000, and may not exhibit a measurable amount of water-softening. When measurable water-softening takes place, then it is axiomatic that *insoluble* precipitates form, even if there be no available surface for adsorption (quantitative precipitation). In the use of modified fatty acids, even if the amount of calcium or magnesium salt formed is within the limits of water-solubility of such calcium or magnesium salts, it is possible that adsorption of these still soluble magnesium and calcium salts takes place from solution, due to the peculiar forces above indicated. In other words, instead of possibly mere physical adsorption of certain magnesium and calcium salts, there may result a selective adsorption, which renders dissolved magnesium and calcium salts (present in amounts smaller than their saturation limits) insoluble by combinations having at least some characteristics of true chemical combination.

In emulsions generally the liquid with the greater surface tension, against the other liquid constituting the other emulsion phase, and especially after allowing for mutual saturation, and solution of the emulsifier (usually a soluble colloid in the other liquid), is almost always, if not invariably, the dispersed phase. Sometimes the situation is confused by the presence of a polar or multipolar emulsifier which orientates in one manner against air, for example, and in another manner against water or oil. Thus to reverse or invert an emulsion these 'surface' tensions must be reversed. In an oilfield emulsion, even the removal of the relatively non-polar oleophile colloid from the oil (unlike the removal of soap from an aqueous solution) would not markedly raise the surface tension of the oil. The removal of soap from water restores the original high surface tension thereof. For this reason one cannot, under conditions of commercial use, reverse or invert an oilfield emulsion by the conventional use of modern chemical demulsifiers.

However, by making the surface of contact between two adjacent or touching water droplets permeable or wettable by brine, coalescence is permited to take place; and it continues until the droplets grow by repeating the process, to the point where, according to the predictions of Stokes' Law, the droplets of water go to the bottom of the vessel. At this point, emulsifying films or encasements of water which could keep minute droplets of insignificant weight apart are no longer strong enough to prevent droplets from running together or combining; or to put it another way, the point is reached where the greatly increased size of the droplet ruptures the protective film.

Hence, the demulsifying action of the modern chemical demulsifying agent is in the direction of reversion or inversion of emulsions, but only so far as to break the emulsion, and not so far as actually to reverse or invert the emulsion under ordinary conditions of use.

It may be well to remind the reader that the previous treatment of adsorption, and more particularly of polarity, has been one of convenience and brevity rather than a comprehensive treatment. In the modern theory of valency, polarity is perhaps most suitably employed in connexion with polar moments, dielectric constants, considerations of electrovalency versus covalency, comparison of ionic and atomic compounds, &c. The colloidal concept of polarity, however, still has its convenient application in such instances where the text clearly indicates its usage. What has been said previously in regard to adsorption and valency is indicated or summarized in a few words by Speakman [38, 1935], in which he states: 'There is no doubt that such phenomena as the adsorption layers studied by Langmuir are due to dative covalency.'

Testing of Emulsified Oil

Any consideration of the testing of emulsified or 'wet' oil demands reference to the work of Woelflin [42, 1932; 43, 1934; 44, 1932; 45, 1932]. The principal tests made on emulsified or 'wet' oil are for the purpose of determining the water content and the specific gravity of the 'dry' or clean oil component of the wet oil. The water content is determined either by centrifuge test or by the distillation method. Both of these methods have been standardized by the American Society for Testing Materials. The test for the gravity of the dry oil component of emulsified oil has not been standardized by this Society.

The centrifuge method that is used in the oil industry is based on the A.S.T.M. Method D. 96, 'Standard Method of Test for Water and Sediment in Petroleum Products by Means of Centrifuge'. In this method 50 ml. of 90% benzol and 50 ml. of the oil to be tested are placed in 100 ml. centrifuge tubes, shaken vigorously, heated to 120° F. for 10 minutes, again shaken, and centrifuged. The centrifuging precipitates the emulsion, water, and sediment.

The changes that have been made in this method by the companies using it consist largely in replacing the benzol diluent with either gasoline; gasoline-carbon bisulphide mixture (ratio 3 : 1); casing-head gasoline-carbon bisulphide mixture (3 : 1); di-ethyl ether; gasoline-di-ethyl ether mixture (3 : 1); or petroleum ether-benzol mixture (3:1). The change in diluent was made to obtain a better solvent for the asphalts and waxes present in the wet oil, and to allow all the emulsion to be precipitated to the bottom of the tube during centrifuging, by increasing the gravity differential between the oil and water layers as much as possible through the use of diluents of lower specific gravity.

The centrifuge method outlined above precipitates the emulsion in the tube without resolving it into oil and water, except where the particle size of the water droplets in the emulsion is extremely large or the films are very unstable. As much as 50% of this precipitated emulsion is commonly oil. If the reading is considered to consist of foreign matter only, and hence to be of no value, a large error may result; and, since such oil content of the emulsion is recoverable, it is desirable to obtain an estimate of the actual total water content of the wet oil by the centrifuge test.

To determine this, and to eliminate the error above suggested, a demulsifying chemical reagent, such as Tret-O-Lite, is added to the centrifuge tube just before heating, only a few drops being required. In a number of cases a 5% solution of phenol in the diluent has been used. This latter procedure will introduce error into the determination, since the phenol will divide between the oil and water phases according to the partition coefficient.

The use of Tret-O-Lite as a demulsifying chemical in centrifuge tests on wet oil has been found to resolve the wet oil into oil and water, and show the total water content of the wet oil, which the A.S.T.M. centrifuge method commonly does not show.

The determination of water in wet oil by the distillation method is made according to the A.S.T.M. Method D. 95, 'Standard Method of Test for Water in Petroleum Products and other Bituminous Materials'. This method consists in distilling a measured quantity of oil mixed with a diluent and collecting the distillate in a graduated receiver. The receiver is of such design, and is attached to the condenser and distilling flask in such manner, as to permit the excess of the non-aqueous phase of the distillate to return continuously to the distilling flask.

Because the water-by-distillation method referred to above was developed for distilling relatively dry oils it is not entirely applicable, without modification, to the distillation of wet oils with water contents above 25%. For these oils a trap larger than the 10-ml. A.S.T.M. trap (which is the only one obtainable commercially) is necessary, or a smaller sample must be employed.

The water content as determined by distillation should be corrected for the difference between the volume of salt-water present in the wet oil and the volume of the distilled water measured in the receiver. This correction will vary with the salt concentration of the water from 0% for a water containing no salt to 8·2% for a water containing 20% salt (calculated as sodium chloride). For southern California, where the average specific gravity of the water is approximately 1·02, this correction is 1·3%. When this correction is applied the results of the water-by-distillation tests are well within commercial accuracy.

No method for determining the specific gravity of the dry oil component of wet oil has been standardized by the A.S.T.M. However, several methods can be used for this purpose.

A chart for determining the gravity of the dry oil component, when the gravity and water content of the wet oil, and gravity of the water are known, was prepared and published by Woelflin in the *Petroleum Engineer* [43, 1934]. This chart is based on calculated values, and is theoretically accurate, since there is no change in volume during emulsification. The accuracy with which the gravity can be determined from this chart will depend on the accuracy with which the gravity and water content of the wet oil and the gravity of the water are determined.

Other methods depend on resolving the wet oil into oil and water and then measuring the gravity of the separated oil by means of a hydrometer, using the A.S.T.M. Method D. 287 and correcting the observed gravity at the observed temperature to the gravity at 60° F., by using the 'National Standard Petroleum Oil Tables' as published in the U.S. Bureau of Standards, Circular No. 154.

The most satisfactory laboratory method for obtaining the dry oil component for gravity test is to add a small amount of demulsifying chemical reagent, such as Tret-O-Lite, to break the emulsion and allow the water to settle out. This can usually be accomplished at room temperature, especially with low viscosity oils. With the higher viscosity oils, separation can be obtained by putting the wet oil in a closed container capable of withstanding pressure; adding Tret-O-Lite, heating to allow separation to take place; and again cooling before opening the container. When it is desirable to speed the separation of the water, the wet oil containing Tret-O-Lite is centrifuged, using the same equipment as when making water-content tests by centrifuge.

It is always necessary to separate the wet oil into clean oil and water in order to obtain a sample of clean oil suitable for the gravity test; and it is not merely sufficient to remove the emulsion as such by centrifuging. Dow [13, 1926] has shown that the bulk oil may not have the same gravity as that part of the oil that is separated with the emulsion during centrifuging. A mixture of all the oil after removing the water is therefore necessary.

Tests of this character are not limited solely to wet oil, but, of course, are applied to dehydrated oil to ensure that such oil comes within the pipeline requirements. (Usually ½% total foreign matter is allowed, but it may be higher or even lower than this percentage in certain instances. For example, in California the maximum amount of foreign matter permissible is commonly 3%.) In some instances it is desirable to use the type of centrifuge tube having a long graduated tip attached to the body of the tube, the tube holding a considerable quantity of dry oil and solvent, in order to determine accurately the exact amount of water and other impurities in the so-called dry oil.

Examination of Chemical Demulsifying Agents

Examinations of chemical demulsifying agents are generally of the following kinds:

(*a*) Tests to select the best chemical demulsifying agent for a particular emulsion.

(*b*) Tests on chemical demulsifying agents in order to ascertain their qualitative and quantitative composition.

(*c*) Tests on chemical demulsifying agents to determine the most suitable one for use with a conventional electric dehydrater.

The testing of chemical demulsifying agents in order to select the one best adapted to treat a particular petroleum emulsion may be conducted either in the oilfields, where the emulsion is available, or else in a chemical laboratory, possibly at some distance from the oilfield. The best tests are obtained on freshly produced samples of emulsion, since some emulsions change rapidly, even within a few hours after the sample is taken. Some emulsions break rapidly, on standing, or owing to the vibration which occurs during transportation. Some emulsions become more difficult to treat after ageing a few days. If tests are made in the field, however, it becomes necessary to resort to methods of examination which do not permit the same degree of refinement that is possible under laboratory conditions with more elaborate equipment. In many instances the results obtained in the field are confirmed in the laboratory as an added precaution.

The testing of crude oil emulsions in order to discover the best demulsifying agent, or, inversely, the examination of a number of demulsifying agents to select the one best adapted for 'treating' or resolving a particular emulsion, is generally carried out in substantially the following manner: A representative sample of the emulsion is first obtained. This may be a relatively easy task, or it may be

relatively difficult. In the case of wells being produced through restrictions, under a high pressure, it is sometimes desirable to add the demulsifying agent before the fluids pass through the restriction of a 'choke' device; and the sample which is obtained for testing must at times be obtained after the fluids have passed through the choke device. It is quite possible that the nature of the emulsion before and after passing through such choke device is entirely different. At other times the sample is taken by opening a small valve. In this case the nature of the emulsion may change after passing through the small sampling valve. In any event, a representative sample must be obtained, or at least one which is as nearly representative as circumstances will permit. A centrifuge test is generally made on such sample by means of a small manually operated portable centrifuge, using 15-ml. tubes which employ a 5- or 10-ml. sample of emulsified oil, to determine its water and emulsion content.

The first series of tests of chemical reagents may be made with twelve, twenty-four, or even forty-eight different demulsifying agents of the type generally employed in that particular field, or of similar types. Four-ounce cylindrical oil sample bottles may be used. Uniform 100-ml. samples of the emulsion (after removing the free water, if any has separated from the emulsion on standing) are poured into the bottles. By means of a glass rod, a thin, rounded, wooden stick, or any other suitable means, a drop of each of the demulsifying agents is added to the respective samples of emulsion. Needless to say, the viscosity and surface tension of various demulsifying agents will vary, and as a result the various droplets may vary somewhat in size. However, an effort is made to obtain as nearly as possible uniform drops of the demulsifying agents. The mixtures of emulsion and the demulsifying agents are shaken vigorously for several minutes. When the shaking is completed the bottles are allowed to stand at atmospheric temperature, and the tendency to break or the completeness of break is noted. If the emulsion is of the kind which will not break or separate without the action of heat, then the various samples, after shaking, may be placed in a water bath, heated by any suitable means. If heat is employed, constant observation is necessary in order to select those demulsifying agents which break or resolve the emulsion most quickly. Approximately six of the best demulsifying agents which show a complete break, or almost complete break, at atmospheric temperature are selected and the remaining demulsifying agents are discarded, at least temporarily.

These tests are then repeated, using the selected demulsifying agents, but instead of adding the reagent in the form of a drop, it is added accurately in the form of a solution. This solution or dispersion is of a definite concentration, generally 5 or 10%. It may be a solution or dispersion in water, gasoline, or kerosine. When the demulsifying agent is soluble or dispersive in both water and oil, it may be tested in both ways. The solution is added by means of pipette, e.g. a 1-ml. pipette, graduated to 0·01 ml. The solution is added at a predetermined ratio compared to the emulsion, which may be 1:2,000 or 1:5,000, &c., whatever ratio is desired, based on experience in treating that particular type of emulsified oil, and the rapidity and completeness with which the emulsion broke in the previous tests. In these tests careful observation is necessary to see that the separation of water in the test is complete, i.e. that the water is equal in amount to that indicated by the preliminary centrifuge tests on the emulsion before treatment. If a water bath is employed, then the temperature of the bath is carefully maintained at some predetermined temperature, usually the temperature at which the field installation will be expected to operate, such as 120° F. Under these circumstances, the best two or three demulsifying agents are selected, and the tests repeated at a slightly higher or considerably higher ratio (i.e. with less chemical), so as to find a ratio where only one, that is, the best demulsifying agent, will be satisfactory. At this stage the tests are conducted with the same care as previously; and, in addition, the dehydrated oil may be withdrawn and examined by means of the centrifuge in order to be certain that dehydration has been complete. All sorts of variations of this procedure are employed, but in a general way the operations involved are as indicated.

Experience has shown that this method of testing will select the better of two reagents if the difference in demulsifying efficiency between the two is as great as 10%. If a demulsifying agent is selected in this manner, it may not necessarily be the best; it may be only the second best or third best, but the best one, selected by more carefully conducted methods under laboratory conditions, will not be more than 10% better than the one selected by this relatively simple procedure.

In the laboratory the tests are conducted somewhat similarly, in many instances using larger samples, such as 200 ml. Agitation is not limited to shaking methods, but stirring with an agitator paddle or blowing with air, or even with a gas, may be employed. In the laboratory final tests are made on larger samples, for instance, on 1-litre samples. Then, too, in the laboratory, various methods of heating the sample may be employed. The laboratory results, however, are always based on the assumption that the emulsified crude oil, after being transported to the laboratory, is in the same condition as when it was taken in the oilfield. If the nature of the emulsion has changed, and the emulsion has become either less stable or more refractory, then the laboratory tests, regardless of the precision and accuracy with which they are conducted, may not be as valuable as the tests performed in the oilfield.

Tests as to the qualitative composition of a demulsifying agent have little meaning except to those who are primarily interested in the manufacture of demulsifying agents or in research work connected therewith. The user of a demulsifying agent cannot evaluate the demulsifying agent for the purpose of breaking crude oil by means of its composition. Even if the composition of the demulsifying agent were printed on the label attached to the drum of reagent, it still would contribute little or nothing as far as its use or value in treating a petroleum emulsion is concerned. When it is considered that demulsifying agents may contain a variety of materials such as oleic acid, fatty acid sulphates, sulpho-aromatic fatty acids, naphthenic acids, together with various solvents, water, inorganic salts, &c., it becomes perfectly apparent that examination of these reagents for purposes of identifying their constituents or the amounts thereof is a laborious and relatively useless procedure, except to those technologists primarily concerned with the manufacture and improvement of demulsifying agents.

Finally, brief reference to tests conducted in regard to the use of chemical demulsifying agents in conjunction with electric dehydraters is necessary. While chemical demulsifying agents are not infrequently added to emulsions prior to subjecting the latter to electrical dehydration, still it so happens that the chemical reagent best suited for treatment of the oil by purely chemical means may not be the best

one for use in conjunction with an electric dehydrater. Tests made to determine the best chemical reagent for use in conjunction with an electric dehydrater are conducted by means of a miniature electric dehydrater, holding approximately a 1-litre sample, and operating under conditions corresponding in voltage, amperage, temperature, &c., with the conditions under which the actual electric dehydrater functions on a large scale.

Plant Application of Chemical Demulsifying Agents

Chemical demulsifying agents are employed in the treatment of cut or emulsified oil in either a continuous process or a batch process. In a general manner, the steps involved in plant application of chemical demulsifying agents are as follows:

(*a*) Preparation of a solution or dispersion of reagent in water, crude oil, kerosine, gasoline, or other solvent if it is required to employ the reagent in diluted form.

(*b*) Admixture of reagent or its solution or dispersion with the emulsified crude oil in a predetermined ratio.

(*c*) Mild or vigorous agitation or intermingling of the demulsifying agent or its solution or dispersion with the emulsified crude oil, which stage generally marks the beginning of the demulsifying action.

(*d*) Subjection of the mixture of the emulsified oil with the added reagent to a heating action if required.

(*e*) Sedimentation of the mixture of the emulsified crude oil and demulsifying agent by permitting it to stand in a quiescent state, whereby the droplets of water increase in diameter and are subsequently affected by gravity to an extent that the walls or films surrounding them are broken, and water or brine collects at the bottom of the containing vessel. Ultimately there are formed two distinct layers, the bottom one being the previously emulsified brine, and the top one being the dry dehydrated oil.

(*f*) The water or brine is withdrawn and discarded.

(*g*) The dry oil is run to storage and then disposed of, e.g. to a pipeline company.

These steps need not take place in the order indicated, and one or more steps may even be omitted. For instance, the oil may be heated prior to the addition of the chemical demulsifying agent. In some instances the clean oil may separate so rapidly that there really is no quiescent stage, or standing. Other steps may be added, although usually they are unnecessary. For instance, in certain cases the mixture, when almost resolved, may be passed through a tank having a thick filter or series of filters composed of excelsior. In some cases the hay tank has been replaced by a tank containing a bed or beds of gravel of relatively small size, approximately ¼ to ¾ in. in diameter. The treatment of some tank bottom emulsions may require re-emulsification with added brine before subjection to chemical reagents.

Batch processes are probably used to a much smaller extent than continuous processes. One generally finds batch processes employed when the oil production is relatively small, as, for instance, in the case of a well where it may be necessary to operate for a week in order to fill a single tank. By this manner of operation the treatment of emulsion may only require attention once a week instead of continuously. A somewhat similar condition exists in various fields, due to enforced curtailment of production. In some cases a well may be opened only for a few hours per week, or perhaps for a day or two per month. Under these conditions it may be desirable to run the entire production into a tank and then treat at some subsequent convenient time. Likewise, treatment of tank bottoms is invariably a batch process, because tank bottoms accumulate gradually, perhaps over a period of years. After accumulation has taken place, the tank bottoms from several tanks may be collected in a single tank and given a single-batch treatment.

In general, the use of heat in the treatment of emulsions, whether by the batch process or the continuous process, depends largely on two cost factors, namely, the effect of the heat in volatilizing valuable constituents, and the cost of heat. As a general rule, oils should be treated at as low a temperature as possible, for the reason that unless treatment is carried out in a closed system, valuable constituents will be lost. It is recognized that, in general, the higher the temperature the easier the emulsions are to treat, and the less chemical demulsifying agent is required. In some instances, where waste gas is available, the cost of heating is almost nil. Therefore, if it costs substantially nothing to heat the emulsion, it may be desirable to heat as hot as possible, provided no loss of volatile matter results, in order that as little as possible may be expended for chemical reagents. However, if a loss of volatile matter does occur, which is usually the case, it is probably more economical to allocate a larger portion of treating cost to reagent; and to heat no hotter than is necessary to obtain economical treatment. This must depend entirely on local circumstances. In some cases the loss of a degree in A.P.I. gravity may cost the producer 2 or 3 or even 5 cents per barrel in the value of the finally recovered oil. Under such circumstances it is more economical to use more chemical reagent and omit or lower the heat, so as to retain the higher gravity. Volume losses due to heating are also to be considered.

It is usually unsatisfactory to heat oil directly with live steam. In those instances where live steam is used directly for heating oil, the steam acts to agitate the mass. If live steam must be used to heat the tank of oil, then the steam should be injected into the water at the bottom of the tank, and should be permitted to condense in this water and not escape as steam into the upper layer of oil or emulsified oil. If the water of the tank is highly corrosive, a set of coils may be placed above the water-level and in the oil layer. These coils should be connected with an outside heater. This heater should hold fresh non-corrosive water which is used over again in the closed system, similar to a vapour-heating system employed for ordinary residential use. Various modifications of these simple methods of batch treatment are found in oilfield use, depending on specific local conditions.

The simplest batch treatment is conducted in substantially the following manner: The tank is equipped with enclosed steam coils located close to the bottom of the tank. These steam coils are covered with water, to a height above the coils of perhaps 6 in. to 2 ft. The emulsified oil to be treated floats on top of this water. The water in the bottom of the tank is generally a hard-water brine, just as it is available from the producing wells or as it separates from the emulsion. The chemical demulsifying agent is poured into the top of the tank, either as such or in the form of a solution or dispersion. Generally, the contents of the tank are heated by means of the enclosed steam coils, prior to the addition of the chemical reagent. The best and safest procedure is to have the contents of the tank in moderate agitation before the reagent is added, and to add the reagent slowly. Sometimes the convection currents produced

by the hot water in the bottom of the tank cause agitation sufficient to mix the chemical demulsifying agent or its solution or dispersion into the emulsified oil. If this agitation is not sufficient, then either an air-line or a gas-line must be used to ensure sufficient agitation. It would even be possible to use a pump by which hot water or oil is withdrawn from the bottom of the tank and pumped back into the tank at the top, although this is rarely necessary. In some instances the tank may be heated by what is known as a thermo-syphon, and this may produce sufficient mild agitation. As a rule, the least agitation which will give uniform distribution of the demulsifying agent is most desirable, but a few emulsions require excessively vigorous agitation.

The majority of cut or emulsified crude oils are treated by continuous processes. Even if oil as produced by a well is not cut, there is generally a settling tank in which the fluids, consisting of oil and brine, are received after leaving the well. Oil-wells do not ordinarily produce oil alone, but produce both oil and water, and also gas, in many instances. Since the volume of water produced is often many times as great as the volume of oil, a settling tank is found on practically every lease, by means of which the unemulsified water and oil are separated. The separated oil is withdrawn to storage, awaiting its acceptance by the pipeline company.

The simplest treatment attempted might be an effort to heat the water in a settling tank, or else to conduct the oil into the settling tank by means of a large vertical pipe of 10 to 12 in. diameter, leading through the upper oil layer and into the bottom water layer of the settling tank, but not resting tightly against the bottom. The purpose of this intake is to obtain more quiescent conditions by preventing the incoming fluids from intermingling with the already separated oil in the top of the tank. Such a settling tank might also be equipped with an enclosed steam coil so as to raise the temperature to a moderate degree. However, bearing in mind that it might be somewhat expensive to heat a single tank, and also bearing in mind the loss of valuable volatile constituents, the probability is that such a condition would be handled by the simple expedient of adding a small amount of chemical demulsifying agent continuously, while the oil is being produced.

The demulsifying agent can be added either by means of a 'lubricator' or 'Tretolizer', or else by means of a small proportioning pump. The lubricator or Tretolizer has no moving parts, and is the equivalent of a separating funnel with a pressure-equalizing tube. The lubricator or Tretolizer (the terms are used synonymously) is similar to the separating funnel except that it is of larger size and is fabricated of metal. It may hold, for example, approximately 7 gallons of demulsifying agent or solution. The lubricator may be of any suitable capacity. It may be constructed of a large piece of pipe, placed in a horizontal position. It has an opening for adding the reagent through a strainer; it has a lower opening by which it may be drained. It has a gauge glass, placed parallel to the side of the reservoir, which indicates the height of the liquid in the reservoir. The reagent within the reservoir passes through a sight feed valve. This is simply a valve which can be regulated by means of a small screw, and the chemical demulsifying agent as it passes into the emulsion drop by drop is visible through the glass sight feed chamber. In this way the flow of demulsifying agent may be observed and regulated. There is an equalizing tube which permits the natural gas-pressure from the well or flow-line to act on the space above the demulsifying agent in the reservoir. This lubricator may be attached at any convenient place in the system. The lubricator may be connected very close to the wellhead so as to obtain the benefit of the maximum amount of agitation and also to act on the emulsion before too complete stabilization takes place. Sometimes the best results are obtained by the addition of the chemical into the well, so as to intermingle with the fluids at the bottom of the well prior to their upward vertical travel. Sometimes where an air- or gas-lift is being used on the well to produce the oil, the lubricator may be connected so as to drop the chemical into the air or gas being forced into the well. Under such conditions the lubricator must be so constructed as safely to withstand the high pressure. The lubricator may also be placed on the top of a tank so as to feed the reagent slowly during batch treatment. Lubricators, of course, may become clogged, the rate of flow may change with the height of demulsifying agent in the reservoir, and also with the change in viscosity of the demulsifying agent due to change in atmospheric temperature. The lubricator when once opened continues to feed the demulsifying agent whether fluid is passing through the flow-line or not. For these and other reasons there has been an increased use of small proportioning pumps of the plunger-displacement type for injecting the chemical demulsifying agent into the flow-line or other inlet where the reagent is intermingled with the wet oil. These pumps are of simple construction, and are relatively low in price. They may be regulated so as to feed from approximately a pint to approximately several gallons of demulsifying agent per day. Larger pumps, by means of which large volumes of dilute solution, e.g. as much as 500 to 600 gal. per day, may be injected, are also in use. Pumps require little or no attention, and their action is positive regardless of change of viscosity in the demulsifying agent. They do not clog readily, due to any extraneous dirt which may have been dropped into the demulsifying agent. They may be operated by a motor or from the walking beam of a pumping well. The pumps are the same kind or are similar to those used for pumping lubricating oil in various drip- or splash-type lubricating systems applied to engines and the like. These pumps are sometimes used for adding water-softening reagents to boilers or for similar purposes. The cost of a small pump without motor may be no greater than the cost of a lubricator. The pump is connected to any convenient supply of reagent.

Reference has already been made to heating emulsions during treatment. Crude oil emulsions treated by a continuous process may or may not require heat during the demulsification process. If heat is required, it may be satisfactory to heat the mixture of emulsion and chemical demulsifying agent in the settling tank, or even to have two settling tanks; to draw off as much water as possible at the first settling tank; and then to heat the remaining fluid in the second settling tank. Another suitable method may be to withdraw the emulsified oil layer from the first settling tank, heat it, and then pass it into a second tank where separation is permitted to take place. Any suitable heating device may be used. One of the most satisfactory methods of heating an emulsion, especially after withdrawing the free water, is to pass the emulsion through an old oilfield boiler filled with water and heated to approximately 120 to 180° F. Such boilers may no longer be serviceable for use under pressure, that is, for steam generation, but may be amply serviceable for holding heated water. In this sort

of arrangement the emulsion is led into the bottom of the boiler, and then out of the boiler at some point on the top, such as the dome. This method of heating is very satisfactory, as the boiler may be fired with natural gas controlled by a thermostat. As a general rule, heating by means of direct flame is not satisfactory, because there is a tendency to 'burn' the oil or else to volatilize some of the water into steam. One encounters the same difficulty as when live steam is passed into the emulsion for heating. Sometimes, however, the emulsion is passed through a heater made of two concentric pipes of different diameters in such manner that the emulsion passes through the annular space and the flame is carefully regulated on the inside of the inner or smaller pipe. In a few instances the pipe has been welded or riveted into a steel tank and the flame permitted to play on the inside of this pipe while the emulsion is treated in the tank. It is evident that where there is available waste gas, a very inefficient method of heating may be used which could not possibly be considered if fuel oil would be required for heating.

In view of what has been stated as to plant operation, it becomes apparent that no absolute generalization can be made as to what constitutes the best method of applying a chemical demulsifying agent, except after being fully acquainted with the local conditions under which the chemical demulsifying agent is to be used. Generally speaking, it is true that chemical demulsifying agents can be applied with relatively simple means, often with the equipment available on the lease; and without a great deal of added labour or supervision, so as to treat the great majority of emulsions at a ratio of approximately 1 to 10,000 or more, compared to the recovered oil, and probably at a ratio of 1 to 15,000 or 1 to 20,000 compared to the untreated emulsion; and that, under proper supervision, in most instances the cost of the reagent required will be no more than 1 cent per barrel of recovered oil, and usually less. There may be refractory emulsions where the cost of chemical reagents may rise to 2 or 3 cents per barrel of recovered oil, but there are also a number of instances where the cost of chemical reagent is as low as 0·3 cent, or even 0·2 cent. Naturally, the cost of treating tank bottoms is much higher than the cost of treating fresh production.

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ELECTRICAL DEHYDRATION OF CRUDE PETROLEUM EMULSIONS

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In many oilfields where asphaltic base petroleums contaminated with water are produced, stable emulsions are formed that may be resolved into their component liquids only with great difficulty. Microscopic inspection shows that such emulsions consist usually of minute globules of water suspended in oil, and that though the water globules are closely spaced in the oil mass, they resist coalescence. The water globules are apparently surrounded by an adsorbed film of colloidal asphaltic material which accumulates at the oil-water interface, and this adsorbed film is believed to be largely responsible for the remarkable stability which such emulsions possess. Once formed, they may be kept for years in suitable containers, with little or no apparent tendency to dissociate. Indeed, the adsorbed films apparently become thicker with age, often forming tough layers of coagulated solid material capable of withstanding considerable mechanical distortion without breaking. The water droplets are generally highly saline, and laboratory investigations show them to be electrically charged. Such emulsions are usually considerably more viscous than the oils of which they are partially composed. The percentage of water present in them is quite variable, and may range up to 80% or more. A measurable interfacial tension exists between the water phase and the oil phase of an emulsion, and, in general, the smaller this interfacial tension, the more readily does the emulsion form and the more stable does it become.

The character of crude petroleum emulsions is found to vary markedly, depending upon the percentage of water present, the viscosity and density of the oil, the size of the water droplets, and their distribution through the oil mass. Small, closely spaced water globules form 'tight' emulsions that are more difficult to dehydrate than 'loose' emulsions in which the water globules are larger and more widely spaced. 'Gas-blown' emulsions formed in flowing wells or in wells operated by the gas-lift method are usually of the more refractory type, while emulsions from pumping wells in which the oil and water are less violently agitated are more readily 'broken'. Apparently the presence of gas in association with the oil and water tends to form a more intimate admixture and thus promotes emulsification. The more viscous oils tend to form emulsions of a more permanent character than do oils of low viscosity. Apparently, too, the percentage of water present is a factor in determining the degree of permanence of an emulsion, for if too much water is present, there is insufficient oil to surround and suspend it, and the water rapidly settles out under gravitational influence. Aside from their higher viscosity, oils of high specific gravity (low Baumé or API. gravity) tend to form more stable emulsions than light crudes, because there is less difference in density between the oil and water phases, and consequently less tendency for the water to settle out under the influence of gravity.

Stable emulsions of the character described are produced in large volume in many western and Mid-Continent American oilfields, and their dehydration imposes an economic burden of great magnitude on the producers. This is particularly true in the older fields where water intrusion is more advanced and where the conditions favouring the formation of emulsion are more highly developed. During recent years oil producers have met their dehydration problem in either of two ways. Some have resorted to the use of certain chemical reagents that have been found to be effective in resolving crude petroleum emulsions; others have adopted a process of treatment which involves subjecting the emulsion to a high-potential electrostatic field, which is also successful in bringing about separation of water from the emulsified oil. Neither of these two methods of dehydration is uniformly successful in the treatment of all crudes, and there are many cases where one or the other is the more successful. Often where either method may be satisfactorily employed, the choice is merely a matter of relative cost.

This article is restricted to a discussion of the electrical method of dehydration, use of the chemical methods being described in another article.

Historical Development of the Electrical Dehydration Process

The discovery that crude petroleum emulsions could be dehydrated by electrical means was made by Professor F. G. Cottrell and two associates, H. Buckner Speed and Allen Wright, in 1908, as a result of research conducted in the laboratories of the University of California. The method was an outgrowth of an earlier development, also by Cottrell, in which high-potential current was applied to the condensation of sulphuric-acid vapours and in smelter-fume precipitation. By means of a high-potential alternating current, with suitable spacing of the electrodes in a small laboratory-scale treater, it was found that refractory emulsions from the Coalinga field in Fresno County, California, could be readily dehydrated. The first commercial plant was installed in the Coalinga field in 1909 and was immediately successful, as was also the second plant, installed in the Lompoc field, Santa Barbara County, California.

The first United States Patents on the use of electricity in dehydration of oil were granted to Cottrell, Speed, and Wright in 1911 (U.S. Patents 987,114–17), and for many years the electrical method of dehydration was known among oil producers as the 'Cottrell Process'. In 1911 a company was organized to exploit the process, and the Cottrell patents were assigned to it. Practical application of the process during the early years was slow, due largely to the absence of electric power in most oilfields, but this handicap has been largely remedied during more recent years by the widespread adoption of electrical energy for drilling and pumping purposes. Since its organization, the company formed to exploit the process has maintained a staff of research workers and engineers who have engaged in a broad programme of development designed to perfect

FIG. 1 A series of photo-micrographs on motion-picture film showing several stages in the electrical dehydration of crude petroleum emulsion. (Degree of demulsification increases progressively from left to right)

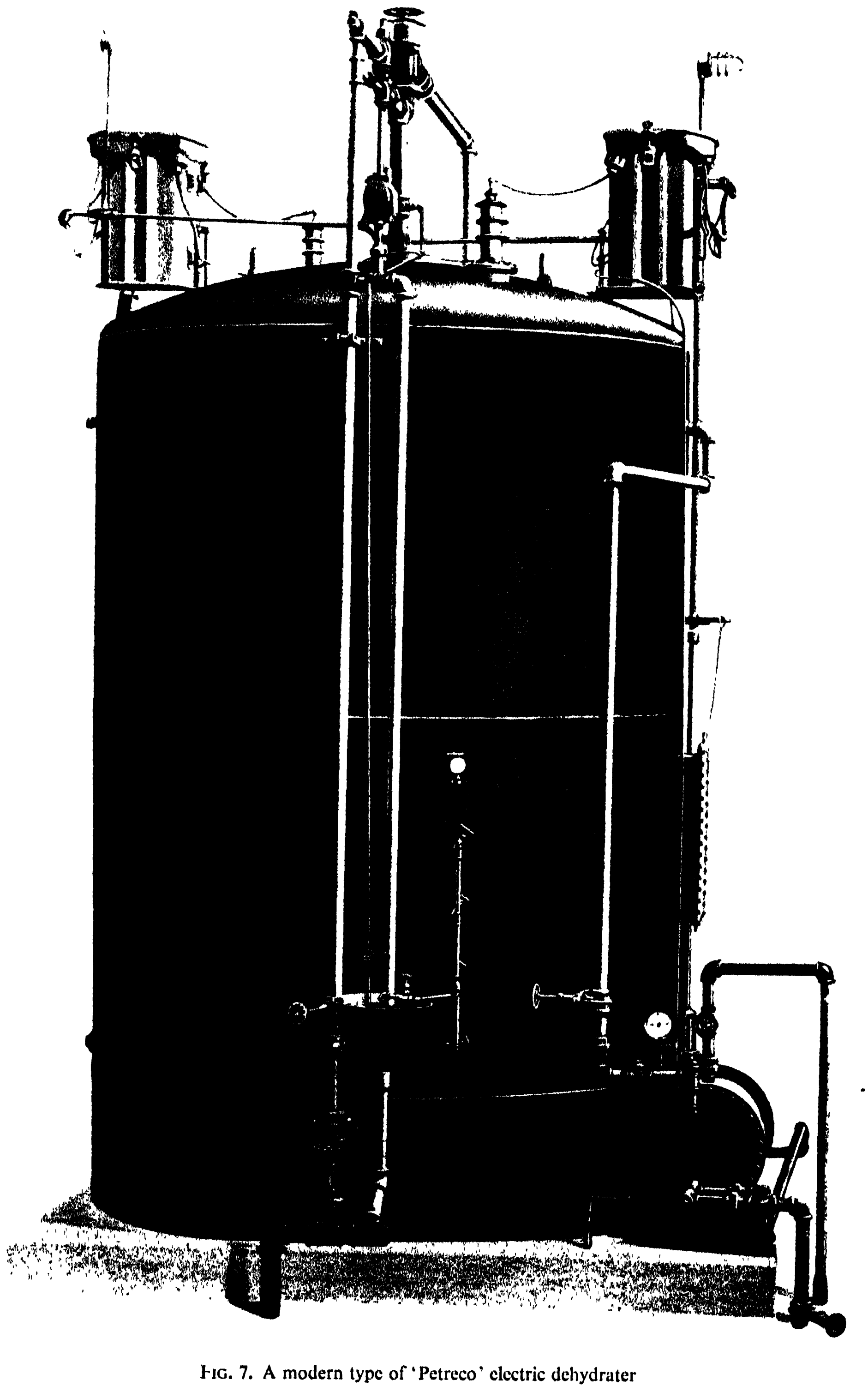

FIG. 7. A modern type of 'Petreco' electric dehydrater

the process and apparatus employed. The electric dehydraters used to-day, while radically different from the early model used by Cottrell, are the result of a natural evolution through a variety of different types.

Fundamental Theory of Electrical Demulsification

When a crude petroleum emulsion is passed between electrodes upon which a high differential of electrical potential is imposed, each water globule becomes charged by induction. The water particles are completely surrounded by the oil phase, a non-conducting medium, and hence retain their electric charge as long as they remain within the electric field. The electric charge, imposed on each water globule, negative on one side and positive on the other, causes the globules to tend to aline themselves in chains between the two electrodes. Simultaneously, either by an altered interfacial tension relationship between the two phases or by a discharge of electric current from one electrode to the other through the alined water droplets, or both, the water globules comprising the electrical path coalesce. A number of small water globules thus form one large globule, and the water particles, thus reduced in number and increased in size, readily settle out of the oil under the influence of gravity. The chain-like arrangement of water globules under the influence of the electric field is clearly apparent under the microscope. (See Fig. 1.)

Before emulsified water particles may be made to coalesce, the adsorbed films which surround them must be ruptured. The character of the enveloping film determines the extent to which the emulsion responds to the electrical treatment. Usually the adsorbed film is readily broken, but in some emulsions the films are so stable that the electrostatic forces developed may be incapable of rupturing them. The potential used depends upon the dielectric characteristics of the oil phase, the nature of the adsorbed films, and the distance between electrodes. It can preferably be expressed as a voltage gradient, or a certain number of volts per linear inch of distance between the electrodes. Gradients as high as 100,000 volts per inch are reached in some types of treaters, but values ranging between 5,000 and 10,000 volts per inch are usual.

By intensive studies of the physical properties of crude petroleum emulsions over a period of many years, and of the results secured by electrical treatment of them in the field, engineers can usually predict the form of treater, voltage, and spacing of electrodes that will give best results, on the basis of a laboratory examination of a sample of the oil to be treated. Such studies commonly include determination of the interfacial tension between the oil and water phases (with the aid of the DuNoüy Tensiometer), the density and viscosity of the oil, and the size and distribution of the water globules in the emulsion. The latter property can be readily determined by microscopic inspection. Many routine tests on a great variety of oilfield emulsions to determine their refractive indices, resistivities, dielectric constants, polar moments, and chemical content of the water present have also been made.

Electrical dehydration of petroleum emulsions occurs in two distinct steps. In the first, action of the electrostatic field causes the minute water droplets to coalesce, forming larger droplets. In the second stage, the large drops of water settle out under the influence of gravity. In modern treaters both steps are accomplished in the same treater. In earlier types of treaters settling of the water was accomplished in a tank separate from the treater in which the electrical treatment of the emulsion was conducted.

In most cases both stages in the process are facilitated by heating the emulsion prior to treatment and keeping it at an elevated temperature until the water has separated out. Temperatures of the order of 120 to 180° F. are commonly employed. At such temperatures the viscosity of the oil is materially reduced, the interfacial tension between the oil and water phases is lowered, and the difference in specific gravity between the water and the oil is increased. Lowering the interfacial tension between the water droplets and the oil mass in which they are suspended decreases the stability of the emulsion and assists the electric field in bringing about coalescence of the minute water particles. Reduction in viscosity and increase in the differential density will facilitate subsequent gravitational settling of the water. Application of heat is not always necessary, however, satisfactory dehydration being occasionally attained at normal wellhead temperatures. Treatment temperatures in excess of those necessary for satisfactory dehydration should not be used, as evaporation losses in the stock tanks receiving the oil after dehydration are likely to be larger at higher temperatures.

Occasionally the overall efficiency of dehydration is increased by a combination of chemical treatment methods with the electrical method. When this is practised a suitable demulsifying reagent such as Tretolite is added to the oil in advance of the electrical treatment. The chemical serves to modify the interfacial tension relationships and to reduce the stability of the emulsion. The efficiency and throughput of the electrical dehydrater is thus increased, and it may be possible to conduct the whole operation at a lower temperature than would otherwise be necessary. If chemicals alone were used, the quantity and cost of the reagent might be excessive. If the electrical process alone were used, the feasible throughput might be low. High temperature might be necessary with either the chemical or electrical method operating alone. A combination of both processes might permit of large throughput for the electric dehydrater, with low temperature and small consumption of chemicals. The overall cost per unit of treated oil produced may thus be a minimum through a combination of the two methods of treatment. It is believed, however, that the circumstances under which such combination can be advantageously used are unusual, and that normally the most economic result would be achieved by the use of either one method or the other.

Types of Dehydraters

As suggested in a previous paragraph, the modern dehydrater has evolved through the development of a variety of different styles of treaters and types of electrodes. At least four fundamentally different types have been commercially installed and successfully operated, in addition to the type of treater originally designed and installed by Cottrell and his associates. Furthermore, there have been several different variations of certain of these fundamental types. Space here permits of but brief description of a few of the more widely used styles of dehydraters.

1. The Revolving-disk Electrode Treater. Early installations of electrical dehydraters, particularly in the California fields, made use of a double-walled, vertical cylindrical treatment tank *A*, 3 ft. in diameter and 8 ft. high, supporting a metal spider *B*, and provided with an inverted

conical top covered with 2 semicircular hinged lids, normally left open for inspection of the oil-level in the treater. (See Fig. 2.) The spider provides a thrust bearing for a vertical shaft *C*, which is caused to revolve by a bevelled gear attached to its upper end, the gear meshing with a pinion on a horizontal line shaft *D*, driven by an electric motor *E*. Attached to the vertical shaft *C*, below the bearing and spaced at equal intervals apart, are several disks made

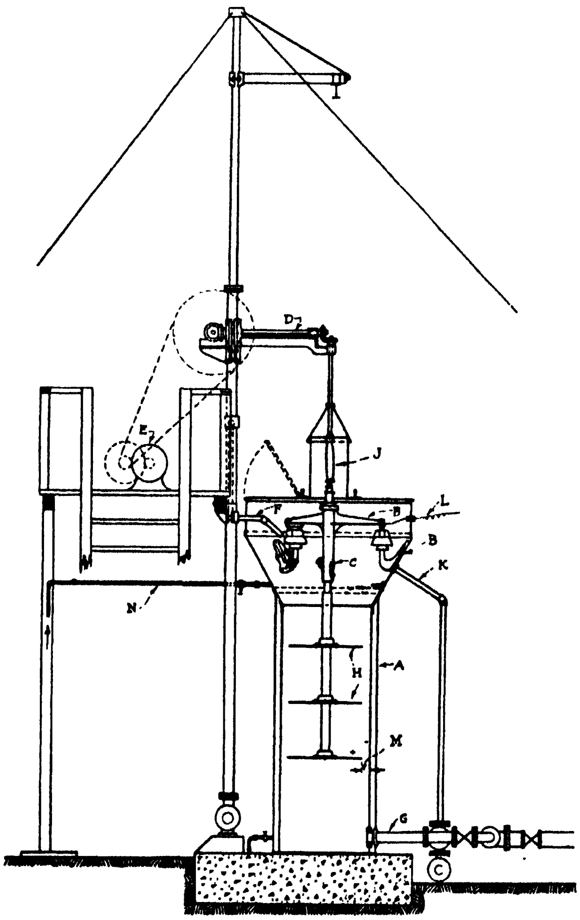

FIG. 2. Vertical section through 'Revolving-disk' type of 'Petreco' treater.

of heavy sheet-steel and of a diameter such as will leave a suitable current gap between the edges of the disks and the inner walls of the tank. The tank is maintained almost full of oil, which circulates through it at a uniform rate, entering through pipe *F* near the top, and leaving by pipe *G* at the bottom.

The revolving shaft to which the disks are attached is made one electrode, and the grounded shell of the tank the other, of an electric circuit which carries a voltage of from 5,000 to 13,000 (usually about 11,000) volts, which is sufficient to establish a strong electrostatic field between the edges of the disks and the walls of the tank, and to permit a discharge across the current gaps at the edges of the disks when the chains of water globules are formed.

The revolving disks serve to keep the fluid in the tank agitated, thus bringing all water particles under the influence of the current. Rotation of the central electrode also accomplishes a continual interruption in the electrostatic field, preventing short-circuiting of the electrodes through layers of water which might form if both electrodes were stationary. As the oil flows down through the treater, it must pass successively through each annular space between the edges of the disks and the cylindrical walls of the tank. The number of disks and the current gap are variable factors that are determined experimentally for different types of emulsion, but there are usually either 3 or 5 disks, and the current gap varies between 2 and 6 in. The oil in the treater is heated to a temperature of from 125 to 180° F., averaging about 135° with California crude, by a steam coil placed in the bottom of the treater below the revolving electrodes. Frequently, too, the oil is heated in receiving tanks before it enters the treater.

Oil and water leaving the treater flow to a settling tank of ordinary cylindrical form, in which the water settles under the influence of gravity. It is usually necessary also to equip the settling tank with steam coils so that the viscosity of the oil may be kept low while the settling process is in progress. Water is occasionally drained from the bottom of the tank by a suitably placed bleeder, while oil is skimmed from the fluid surface with a swing pipe.

Units of the type described above are arranged in groups of 2, 4, 6, or 8. One motor will be sufficient to rotate the electrodes of as many as 8 treaters, and one 300-bbl. settling tank will be sufficient to receive the flow from them. The piping, valve, and power control is much simplified by this arrangement. The capacity of a single treater of the proportions given above will vary from 300 to 1,600 bbl. per day, depending upon the character of the oil and the condition and amount of water present. A 2-h.p. motor is sufficient to revolve the electrodes of a 6-treater unit.

While many revolving-disk electric dehydraters were installed in the California oilfields prior to 1922 and yielded entirely satisfactory results, they possessed certain inherent disadvantages which have been avoided in more recent types of treaters. Some of the revolving-disk treaters are still to be found in operation in the California fields, but none have been installed since 1922, and this type of treater is now considered obsolete.

2. The Horizontal Flow ('H.F.') Closed Treater. Among the disadvantages of the revolving electrode type of treater is the open space above the oil-level in the top of the treater with opportunity for access of air, due to the fact that half of the cover is customarily left open. This leads to evaporation losses and occasional fires. Furthermore, the electrical field is confined to the relatively thin zones in the immediate vicinity of the edges of the revolving disks, and the efficiency and throughput of the treater are at times not as great as could be desired. In the 'H.F.' type of treater designers have sought to remedy these difficulties. The new design, introduced about 1923, struck out along radically different lines and, though operating on the same fundamental principles, yet provided an entirely different form for the treater, as well as a different type of electrode with a different direction of flow of fluid through the treater and between the electrodes. Furthermore, the 'H.F.' treater is entirely closed, so that there is little or no opportunity for evaporation loss or fire. It achieved a considerable increase in efficiency of operation and larger throughput capacity.

The 'H.F.' treater combines electrical treatment and gravity settling of water from the oil in one tank. Preheating is accomplished in a pipe form of heat exchanger, so that no supplementary tankage is necessary. The treater tank *A* is cylindrical in form, 10 ft. in diameter and 12 ft. high, and has a capacity of about 185 bbl. of fluid. (See

Fig. 3.) The oil to be treated is forced into the treater with the aid of supply pump *B*, through preheater *C*. Steam enters the preheater through pipe *D* and exhausts through *E*. The heated emulsion enters the treater tank through pipe *F* and is discharged upwards through pipe *G* at the centre of the tank, through concentric tube *H*. Flowing upwards through *H* the oil is discharged between the two electrodes, conical in form, the lower of which, *I*, is stationary and electrically grounded. The upper electrode *J* carries a high potential current and is suspended on a supporting frame in such a way that it may be moved up and

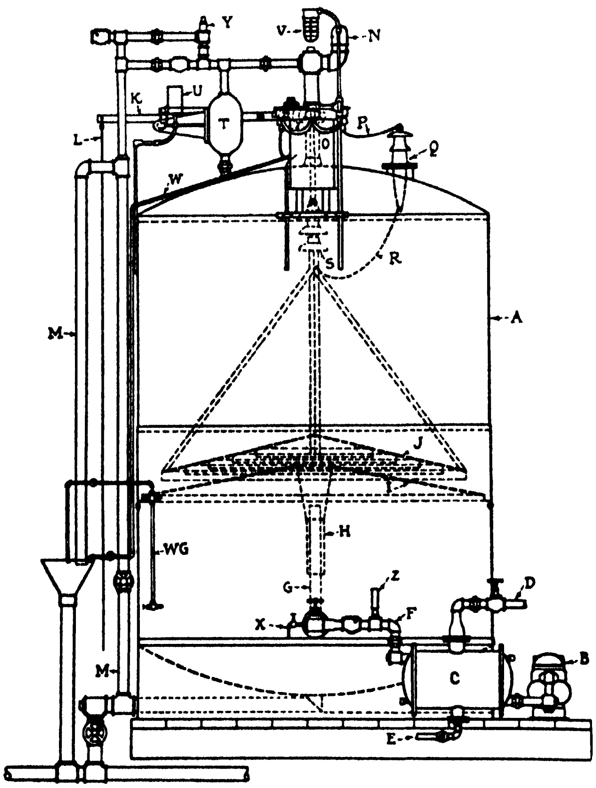

FIG. 3. Vertical section through 'H.F.' type of 'Petreco' dehydrater.

down through an interval of several inches with the aid of pivoted beam *K*, which is connected at its outer extremity by cable *L*, with a small motor-actuated crank not shown in the drawing. The two electrodes are thus held from 4 to 8 in. apart, the distance between them continually changing as the upper electrode slowly moves up and down. The lower surface of the upper cone carries a series of narrow metal strips supported in such a way that their edges project downwards.

Emulsion flows downwards and outwards from the centre, between the two electrodes, where it is subjected to electrical treatment which frees the water from the emulsifying bonds. The water settles to the bottom of the tank and is drained off through bleeder-piping *M*, which is so arranged as to maintain the treater at all times filled with fluid. Oil rises to the top of the fluid in the treater by reason of its lower density and overflows through pipe *N* to nearby storage tanks. Electric current enters through transformer *C*, wire *P*, insulating bushing *Q*, and flexible conductor *R*, which is attached to the frame supporting the upper electrode. The latter is insulated from the tank and external equipment by insulators *S*, which form a part of the electrode suspension mechanism. A liquid-level regulator *T* is so connected with a safety switch *U* as to shut off the current during the time that the treater is filling or whenever the liquid-level in the treater falls below the top. Pilot light *V* indicates whether or not current is flowing into the treater. A small sampling tube *W* permits of drawing a sample of treated oil from the discharge line, and another valve *X* provides a means of sampling the incoming fluid. A pressure relief valve *Y* permits the fluid to escape from the treater in case the control valves on the discharge lines are closed, or whenever the treater is subjected to pressures in excess of 25 lb. per sq. in., for which safe-working pressure the relief valve is set. A thermometer *Z* in the oil-inlet piping indicates the temperature of the oil flowing from the preheater. Check valves are provided on both the inlet and outlet tubing. A glass water-gauge *WG* indicates the position of the water-oil surface within the treater.

The 'H.F.' type of dehydrater has a capacity of from 1,000 to 4,500 bbl. of demulsified oil per day, depending upon the character of the oil.

With some oils requiring high treatment temperatures, trouble has been experienced with the 'H.F.' type of dehydrater as a result of formation of gas from the oil. Gas accumulating between the two cones may tend to keep the upper cone afloat, or cause it to tip to one side or another, thus disturbing the normal spacing of the electrodes. The result will be poor dehydration and high 'cuts' in the treated oil. Frothing of the oil at the surface in the upper part of the tank may permit the float to sink below its normal position, thus shutting off the current or leading to intermittent application of the current. To remedy this, the interior of the treater may be maintained under moderate pressure by placing a spring-loaded relief valve in the dehydrated oil discharge line. This valve holds a constant back-pressure on the treater, irrespective of the rate of flow through it. The treater shell is designed for a pressure of 25 lb. per sq. in., and working pressures as high as 22 lb. are occasionally used. At such pressures most of the vapour and gas are held in the liquid phase or retained in solution in the oil.

Another difficulty occasionally encountered with the 'H.F.' type of dehydrater is that of unusually rapid accumulation of water in the bottom of the treater, so that the water-line rises and short-circuits the current between the two electrodes. Normally this will not happen, particularly with proper adjustment of the outlet valves and occasional inspection of the water-gauge, but the percentage of water sometimes fluctuates rapidly, and under such circumstances this difficulty may occur.

Another style of horizontal flow treater is one in which the cones are replaced by horizontal metal screens. This is the so-called 'horizontal screen' ('H.S.') treater, widely used in Texas, but seldom in California. The 'H.F.' style of electrode is used for 'loose' emulsions of relatively high viscosity, while the 'H.S.' style is better suited to low-viscosity oils of low conductivity. The 'H.S.' electrode is so designed that increased gradients may be secured by using two transformers, one on each electrode. Both styles are useful when dealing with certain types of oil where it is desirable that the emulsion be introduced into the treating zone with a minimum amount of agitation in order to avoid again emulsifying the oil after it has been demulsified, and to facilitate settling of water particles after coalescence.

3. The Concentrated Field ('C.F.') Type of Dehydrater makes use of the same treater shell and exterior arrangements as the 'H.F.' dehydrater described in the

preceding section, except that it is unnecessary to impart motion to one of the electrodes, and hence no motor is necessary. The form of the electrodes and their disposition within the treater, however, are entirely different. In the 'C.F.' treater the necessary interruption in the discharge of current between the electrodes is accomplished by flow of the emulsion between the electrodes rather than upon a movement of one of the electrodes relative to the other by mechanical means. Absence of moving parts, of course, simplifies the design considerably and makes for lower operating costs.

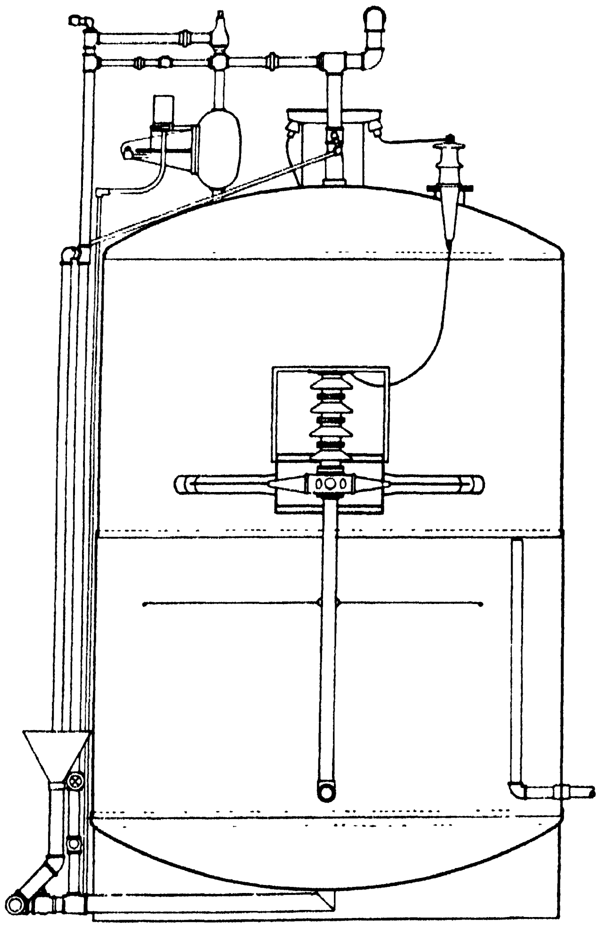

FIG. 4. Vertical section through 'C.F.' type of 'Petreco' treater.

The 'C.F.' treater utilizes a rod type of electrode surrounded by a concentric cylindrical shield 3 to 7 in. in diameter, the emulsion being jetted at high velocity through the annular space between the rod and the shield. In the 'H.C.F.', or horizontal concentrated field type, there are 8 sets of jet-type electrodes arranged within the treater in a horizontal plane so that they radiate horizontally from a central point. The 'wet' oil inlet pipe leads the incoming fluid to this central point and distributes it uniformly through a supporting spider to each of the 8 electrodes. (See Fig. 4.) The cylindrical shields are supported by, and electrically grounded through, the treater shell. The high-potential rods are, of course, insulated from the concentric shields and distributing spider. They carry a voltage of 16,500 volts.

In another variation of the 'C.F.' type of treater two transformers are used and a 'hook-up' which permits of securing 33,000 volts across the current gap between the rods and their surrounding shields. This is the so-called 'D.T.C.F.' (double-transformer concentrated field) type of treater, especially useful in treating gas-blown emulsions in which the emulsified water particles are unusually small and closely spaced. With reference to Fig. 5, which reproduces a design for a treater of this type, a stream of emulsion is ejected from a nozzle H directly towards a pointed rod R, axially alined with, but spaced from, the nozzle. The emulsion stream is split by the rod and flows along

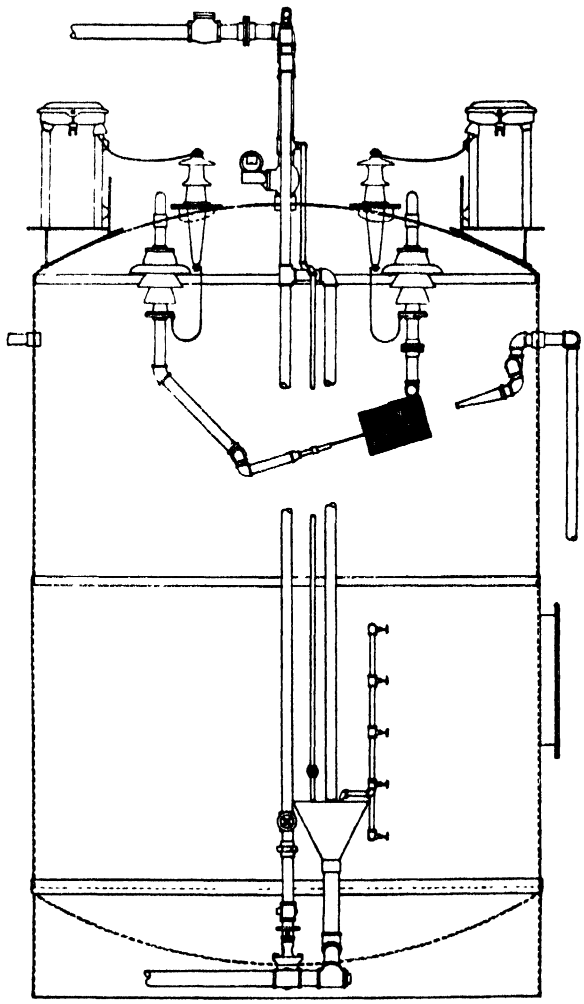

FIG. 5. Vertical section through 'D.T.C.F.' type of 'Petreco' dehydrater.

and completely surrounds it. A shield S completely surrounds the rod, with an annular space of 3 or 4 in. between. Both the rod and the shield are insulated from each other, from the tank, and from the nozzle. An intense electric field is set up between the shield and the rod by means of high-voltage currents received from separate transformers which are connected in series, one transformer being connected to the rod and the other to the shield. Hence the voltage between the rod and the shield is twice that between the rod and the nozzle, or between the shield and nozzle, or between the shield or rod and the ground. Usually two complete sets of electrodes are used in each tank, the two being placed side by side with the two nozzles throwing parallel streams through the electrodes. These electrodes are interchangeable with other designs in the same type of treater shell.

In addition to the absence of moving parts, the 'C.F.' types have the advantage of high throughput capacity and freedom from conditions that in other types lead to inefficiency and interruption in service. They are especially applicable to the treatment of 'tight' emulsions of relatively low viscosity and to emulsions of high electrical conductivity. They have proved especially effective in handling flowing-well and gas-lift emulsions in the California high-gravity oilfields.

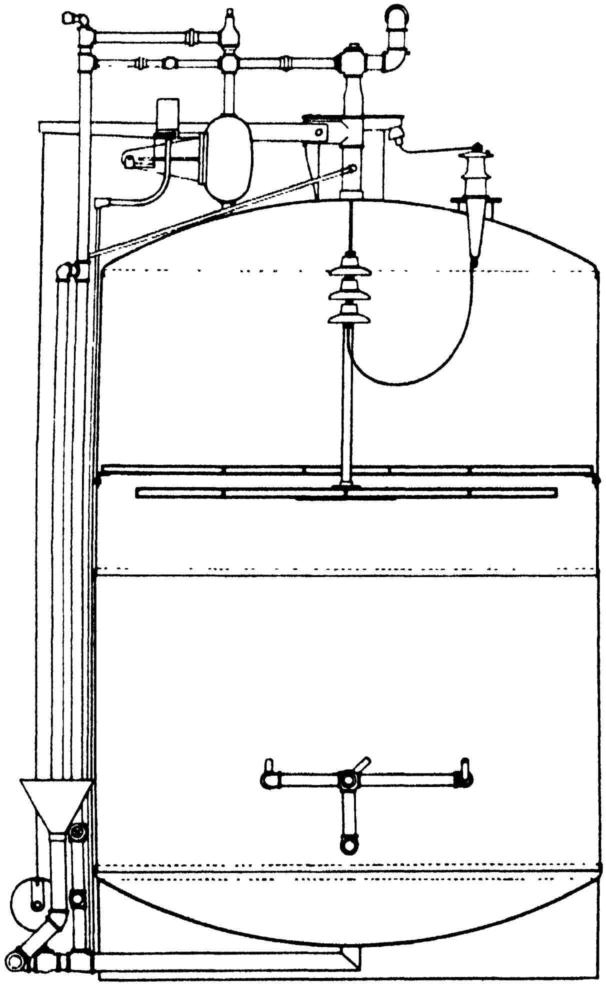

FIG. 6. Vertical section through 'C.R.' type of 'Petreco' dehydrater.

4. The Concentric Ring ('C.R.') Dehydrater, the most recently developed type of treater, like the 'C.F.', has no moving parts and depends upon rapid flow of the emulsion between the electrodes in preventing short-circuiting of the current. Also, the same size and style of treater shell is used as in the 'H.F.' treater, and substantially the same exterior arrangements as are employed with the 'C.F.' treater. Standardizing on size and form of treater shell and service facilities has made it possible to convert the earlier 'H.F.' treaters to the more efficient 'C.F.' or 'C.R.' types at minimum expense.

In the 'C.R.' type of treater the electrodes consist of 3 or more sets of concentric steel rings, supported horizontally in the treater in such a way that the incoming fluid must pass through and between them. (See Fig. 6.) The concentric rings comprising each electrode are about 5 in. apart, while the adjacent electrodes are about the same distance apart vertically in the treater. The rings of each electrode are 'staggered' with respect to those above and below. Certain of the electrodes are connected with a source of high-potential current, while the others are electrically grounded through the treater shell. A double-transformer type ('D.T.C.R.'), through the use of two transformers, energizes both sets of electrodes, making possible double the normal potential gradient. The incoming fluid is distributed through a horizontal spider comprising 4 pipes of varying length with upturned ends. The distributing spider is placed below the lowermost electrode in such a way that the incoming fluid is jetted upwards between the electrodes.

Like the 'H.F.' type of treater, the 'C.R.' dehydrater is best adapted to the treatment of low viscosity, 'tight' emulsions of high electrical conductivity. Many installations and conversions of the older types have recently been made in the southern California oilfields. The photograph reproduced in Fig. 7 is illustrative of typical modern installations.

In making a choice of one type of electrode or another for a particular oil, designers base their selection in part upon tests of interfacial tension between the oil and water phases of the emulsion. Low interfacial tensions require the use of the horizontal flow type of treater which operates with a minimum of agitation of the fluid after demulsification has occurred. High interfacial tension emulsions, on the other hand, which are not so readily re-emulsified, permit use of the high injection velocities characteristic of the 'C.F.' and 'C.R.' types.

Operating Details of Electrical Dehydraters

Modern treaters of the 'H.F.', 'C.F.', or 'C.R.' types are capable of dehydrating from 500 to as much as 7,000 bbl. of oil daily (clean oil), averaging perhaps 1,500 bbl. The throughput capacity will vary greatly, depending upon the amount of water present, the type of emulsion, and the treatment temperature. Throughput capacity is sometimes limited by the time required to break the emulsion; frequently, however, by the time required for settling after treatment. The rate of settling will be influenced by the difference between the specific gravity of the oil and that of the water, also by the operating temperature and the size of the coalesced water particles. Under average conditions the fluid is in the treater about 2 hours, but not necessarily undergoing treatment during all of this time.

The treatment temperature ranges from wellhead or atmospheric temperature to as high as 180° F., but averages about 130° F. Steam consumption in heating the oil and operating the reciprocating pump necessary in forcing fluid through the treater is low, particularly where several treaters can be operated in a group. A 50- or 70-h.p., gas-fired steam boiler furnishes ample steam for heating the oil and operating the pump for one treater. Often exhaust steam from a power plant operated for other purposes will furnish sufficient steam for heating the oil, and an electrically driven transfer pump may be used for circulating the fluid through the heater and treater. A low-pressure steam plant is quite satisfactory for heating purposes, the condensed steam from the heater being returned to the boiler so that the entire heating system operates in closed-flow circuit. A boiler pressure of about 6 lb. is maintained, and the flow of steam is controlled thermostatically. Such an installation may operate on as little as 30,000 cu. ft. of gas daily. For a 1,500-bbl. daily throughput, raising the

temperature to from 130 to 180° F., the heater should contain about 250 sq. ft. of heating surface.

Either one or two 16,500-volt step-up transformers are used, one side being grounded. The primary voltage is usually either 200 or 440 volts. The actual power consumption is low, ranging from 25 to 50 watt-hours per barrel of dehydrated oil, or, for average throughput, about 45 K.W.H. per treater per day. The current flowing averages about 10 amperes. Where electric power is not otherwise available, it may be economically generated with the aid of a steam turbine-driven generator.

In some instances electrical dehydraters are placed near the well and receive the entire fluid produced after trapping off the gas. Usually, however, it will be preferable to pass the fluid through an intermediate settling tank where the quick-settling water may be 'bled' off before the residual fluid is run to the dehydrater. Often all the flow-lines from a group of wells, or perhaps all the wells on a producing property, will carry the production to a central dehydrating plant. Many economics and greater overall efficiency are realized by concentrating all the dehydration equipment in one central plant. Plants of this character are often situated near the storage and shipping centre. Some oil-producing companies concentrate all their dehydrating activities in each field in a single plant, 'wet' oil from the various leases operated by the company being transmitted by pipelines to the central plant for treatment. In some California fields 'wet' oil is sold by the producers to others who operate the dehydrating plant and prepare the oil purchased from several producers for pipeline shipment to the refinery. Whatever the plan followed in operation of the dehydrating plant, emulsions should not be permitted to stand in storage for a long period of time before treatment. Freshly produced emulsions are more easily and thoroughly demulsified than are 'tank bottoms' and sump accumulations in which the emulsified water has had time to settle thoroughly.

Electric dehydraters are successful in handling a wide variety of oils, ranging in API. gravity from 11 to 40°, and with water content as high as 85%. The water content is readily reduced by electrical treatment to less than 2%, the usual pipeline requirement, often to less than 1%. Wet oils, of course, have a lower API. gravity than the same oils without water, and where oils are bought and sold on a gravity basis it may at times be a considerable advantage to the producer, from the monetary standpoint, to restore the oil to its original gravity by thoroughly dehydrating it. A gravity increase of several degrees is frequently realized by thorough dehydration, and the increased value of the oil will usually more than repay the cost of dehydration.

The modern closed-type electric dehydrater accomplishes demulsification and removal of the water with negligible evaporation loss. Tests made in dehydrating plants in certain southern California fields show losses of less than 0·5° API., and when vapour-tight receiving tanks are used the gravity loss can be reduced to 0·1 to 0·3° API. Corresponding volume losses will be less than 2%, often less than 1%. These losses are not incurred in the process of dehydration, but rather in the subsequent handling of the oil from the dehydrater to storage.

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A METHOD OF WORKING PETROLEUM BY MEANS OF UNDERGROUND DRAINAGE

By PAUL DE CHAMBRIER

Former Director of Mines at Pechelbronn (1894–1921)

Introduction

EVERY petroleum engineer attempts to improve the value of his first borings, and to increase the output in the shortest possible time. He therefore tends to devote his main attention to the richer areas of his concessions, and to neglect the others. Thus there is a waste of crude oil; and this loss is increased by the effect of competition which tends to lower the price of both crude and refined products, by the effect of excise and mining laws, and by the royalties payable in certain countries to the owners of the land. Finally, as the oil-mine is gradually exhausted, the production cost of the oil increases and the working is abandoned before it is actually exhausted.

To this waste of valuable mineral matter must be added one still more important factor. Ordinary methods of working by means of boring only permit of the extraction of a slight proportion of the oil contained in a bed. This proportion has been estimated at 20 or 25%.

Thus about three-quarters of the valuable raw material remain lost in the depths of the earth, where this oil is retained in the sand (gravel, &c.) by means of 'adhesion'. The working of petroleum by means of underground drainage, used for the last 18 years at Pechelbronn, has enabled the waste of raw material to be kept down, and its extraction yield to be doubled. During the Great War the management of the Pechelbronn mines decided to enter upon a risky undertaking. This was to sink a well into a full oil-bearing bed, to dig galleries in it, and to bring the sand to the surface, in order to extract by mechanical washing the paraffin with which it is saturated. The results of this experiment were very different from what had been expected. They led to the discovery of an entirely new process—the production of oil by means of underground drainage. This attempt was based on laboratory work, suggested as long ago as 1897, which enabled the extent of the quantities of oil remaining in the subsoil after extraction by pumping to be estimated. The first question which arises in this connexion is—How is it that the oil-pumps placed over the middle of beds of oil-bearing sand (gravel, shale, &c.) should give such a poor yield?

Under the influence of pressure of the earth's crust, the plastic sand, deposited by waters at more or less remote geological periods, has gradually attained a state of maximum 'settlement': the space which it occupies corresponds to two-thirds of its original volume; it has changed into a rock whose particles are, moreover, cemented together by mineral substances, and such compact rock offers great resistance to the passage of fluids.

Numerous observations go to prove that the oil-vapour, dissolved in the oil at high pressure, is the only motive force capable of carrying the oil to the pumps placed on the beds. In the course of working, this motive force diminishes from year to year, pumping yields less and less, and finally the wells have to be abandoned as soon as the bed becomes inactive, owing to the fact that the excess gas has been given off. This topic will be dealt with later.

The Pechelbronn Beds.

The mining concession of Pechelbronn, with a surface area of about 42,000 hectares, is spread over a region of little hills with shallow valleys, in the Lower Rhine district, between the towns of Hagenau and Weissenburg. On this concession, of which about one-quarter is productive, the zone being worked is confined to a narrow strip, varying from 2 to 7 km. in width, and about 25 km. long. The deposits of sand, &c., included in Oligocene clays, are on the whole oil-bearing; nevertheless, drillings, wells, and galleries have also revealed sands either barren or only partially impregnated. The formations and dimensions of the deposits, likewise the quantity and quality of the oil with which they are impregnated vary, according to the depth and the region. Those nearest the surface show the form of elongated elliptical areas, while at about 90 metres down the beds take the form of regular strata, lying in the direction of the Vosges fault, and having an inclination of about 5 to 7 degrees. The stratification of these oval beds and of the strata has been well defined by the fact that the same beds were worked, underground, between the years 1735 and 1888.

The oil-bearing sand, impregnated with a heavy, viscous oil was taken to a refinery, and extracted with boiling water. Some years before the underground workings were abandoned a chance sinking had revealed a new horizon, about 150 metres down, from which oil spouted spontaneously. The deep strata, since then worked by sinkings, differed from the previous ones not by their 'aspect', but by the quality of the oil with which they were impregnated—a light fluid oil, mean density 0·880, containing paraffin and petrol, and above all, gas, in sufficient quantities to cause the oil to 'spout' between 150 and 450 metres. The gentle dip of these porous beds, in a region enclosed by argillaceous beds showing neither domes nor anticlines, has been disturbed by numerous fractures rising out of the collapse of the Rhine-plain during the tertiary period. Since then, this area, furrowed with radial faults, has been seen to consist of a series of detached 'compartments', some of which are barren, and others more or less productive, along the line of the oil-bearing deposits. The thickness of these deposits varies between a few centimetres and 10 metres, generally speaking about 2 metres. This thickness is an important factor in the underground drainage which is easy and profitable for the thicker and more extensive sand-beds, but difficult for the less extensive and irregularly distributed petroliferous strata.

Recommencement of Underground Working.

The beginnings of a new industry and the circumstances determining its prosperity are always interesting and instructive to know, the more so as the history of an industry pays its tribute to economic science.

The process of underground drainage of crude oil is not the result of a profound scientific investigation—it owes its origin to a combination of curious circumstances. The

old underground workings at Pechelbronn, which have been already mentioned, consisted in extracting from shallow mines oil sand, which, when washed with boiling water, yielded a thick grease, used, without further refining, for lubricating carriage-axles. During the century and a half at this working, the mine engineers were careful to preserve their observations and the results of their work in the numerous mine records.

These documents giving an account of the disposition of the beds have long guided all workings on the concession. Since then, and until 1914, several thousands of borings enabled the geologists and miners to obtain an accurate idea of the stratification and the disposition of the faults in the deep beds. At this time, i.e. shortly before the War, the richest part of the concession, where beds of oil-bearing sand of greater extent and closer to each other were found, was almost exhausted. Sinkings had revealed other beds, quite numerous but more scattered and less saturated, which did not seem to promise possibilities of working much longer. Starting with the idea that the deposits of crude-oil worked by sinking still contained a certain quantity of crude petroleum, and that the pumps had taken off the major part of the excess gas, I suggested, just after the beginning of the War, a reversion to the old method of underground working abandoned thirty years before. M. Nollenburg, director of the 'German Mineral Oil Company', a Berlin mining concern which since 1906 had been acquiring all the Alsatian oil concessions, ordered a careful consideration of this question, and for this reason the valuable documents relating to the old workings were sent to Berlin.

The work lasted more than a year and did not lead to the desired conclusion; mining engineers, geologists, and financiers were dubious of such an uncertain and risky undertaking. It was at this point that the work in the laboratory at Pechelbronn—on the saturation of sand by oil, on its power of absorption and the force of adhesion—enabled us to come to the following conclusions: 'The quantity of oil flowing from a deposit reached by sinking is so small that thorough working of the deposit, with extraction and washing of the sand, will give 2½ times more oil than sinkings at the perimeter of the bed being worked. Moreover, a certain part of the residual oil will flow into the galleries by natural oozing'.

The studies pursued at Berlin by the mining engineers and at Pechelbronn by the chemists had lasted more than two years, during which time the economic conditions of the Pechelbronn industry had changed completely.

Following the War, refined products had quadrupled their value, and accordingly the cost price of the raw material need no longer be taken into account. In Germany, as in most other countries which had been engaged in the world struggle, the additional profits realized by the industrial concerns found their way into State coffers, but the State, on the other hand, made allowances to these concerns, so that they might improve their plant. This last point solved the financial problem of the undertaking. Then the geologists and chemists conferred together, and the mining engineers took charge of the technical side. At the beginning of 1917 the first well was sunk, and the first gallery reached, 150 metres down—the first deposit of petroleum as defined and worked by sinking for more than thirty years.

In the first days following the opening up of the deposit neither the violent escape of gas feared by the engineers nor the oozing expected by the chemists took place. Then gradually from the lower sides of the galleries the miners saw the oil ooze out slowly, forced out by innumerable gas-bubbles. These bubbles, oil-laden, gave a curious explosive sound as they emerged from the capillary interstices of the sandy, well-compacted rock. As the work advanced the oozing increased, the daily output reached 10 tuns; further, after three months the value of the oil obtained had largely covered the initial costs of sinking the first well. This unexpected result allowed us to give up the idea of extracting and washing the sand. We had simply to find the means of penetrating further and further into the oil-bearing gas-charged rock, of extending the galleries, and drainage, while maintaining the safety of the workers.

The technique of this new method of extraction seemed simple at first to the engineers entrusted with its development, but like many schemes evolved hastily, round about the time of the War, it had serious drawbacks. The final procedure was only perfected after serious accidents which took place in 1919. A year before these accidents, and before the definite organization of the first mine the D.E.A. (Ger. Min. Co.) had started two new workings in less productive regions. They never yielded as well as the first spot, where the stratigraphic conditions were peculiarly suited to working by underground drainage.

The Methods of Drainage.

In an oil-bed the sand has the aspect of rock. Compacted as much as possible, it is more or less cemented together by mineral substances, and thus its porosity varies, i.e. the spaces between the grains are not always the same, and their volume referred to a cubic metre of sand varies between 200 and 270 litres at Pechelbronn. These spaces are filled with crude petroleum, with a little salt water, and with gas. The volume occupied by the gas in a 'virgin' bed is negligible in view of its solubility in the petroleum at the high pressure prevailing. A sinking which touches the deposit first of all produces a violent ebullition of the gas, a part of the oil is forced towards the sinking, and the rest, together with the gas which is always being given off, forms an elastic and compressible form, which by its nature finds its way into the capillary interstices of the sand, the more slowly according as the exit formed by the bore hole is small.

During the years in which pumping takes place, the gas-pressure goes on diminishing, the foam blocks up the pores of the sand more and more, the deposits become inactive, and considerable quantities of oil, still gas-charged, are lost for working. What will happen if we then open up a drainage gallery to the rock?

We may note that the 'flow surface' of a gallery is infinitely larger than that of a sinking. At the immediate edges of the gallery walls the gas, in communication with the atmosphere, escapes freely, the foam which was blocking the rock-pores breaks away. The oil, by gravity, tends to descend, and the gas similarly to rise towards the roof of the gallery, where the sand is more free from oil. At a certain distance from the drainage walls these two forces are too small to overcome the resistance offered by the compact sand to the flowing liquid. But by the motive force of the gas the two fluids are separated near the surface of the gallery, where at the same time as the foam breaks away the resistance of the sand wall is diminished. At the surface of the gallery a stable state of flow is established with a clear line of separation between gas and liquid. This explains the fact that the oozing observed only takes place on the lower levels; this apparent level of oozing oil,

formerly identified with the mean level of the oil in the whole bed, has been one cause of error in the first estimates of the yields from drainage. The 'relief' produced by the departure of the gas spreads gradually through the whole bed, its equilibrium is disturbed, it becomes active again, after the period of abandonment following pump working. The gas again becomes ebullient, and its bubbles, whose volume increases with pressure drop, act as air pistons, and proceed towards the drainage galleries, expelling the remainder of the foam which has saturated the deposit. The large evaporation surface of the galleries causes a very rapid escape of the gas suspended in the oil, so that the flow of petroleum from a bed of sand under drainage takes place in a very short time. On the whole, the yield of working by means of well and gallery is equal approximately to that by sinking and pumping. As soon as a mine has been installed, however, extraction by drainage is considerably quicker than that by sinking. It needs only a few months to dig a gallery in the region of former sinkings and to extract from the sand-bed as much crude oil as had formerly been obtained in a considerable number of years. At this moment the gas-pressure is completely exhausted, and the residual oil, incapable of flowing by gravity, remains in the bed in considerable quantities, far in excess of those yielded by drainage.

The Technique of Drainage.

Every drainage working for oil must comprise two working wells and a carefully constructed ventilation system. There are the access-galleries which allow of reaching a particular deposit, or of passing from one deposit to another; then the extraction galleries are laid out in 'square' formation, care being taken that the drainage galleries lie on the lower side of the oil-bearing bed.

From this point the oozed oil is led off in canals and then brought to the surface by means of a crude oil pump. The gallery network thus formed will not have a large excavation volume, since a part of the broken-down rock will serve to fill up the old galleries.

This method of mine working seems very simple, but a mine of this type does show serious danger possibilities from explosion and fire.

Realizing this responsibility the French State Board of Mining has attempted to perfect the method devised by German engineers, and has succeeded in rendering it practicable. Since 1919 there has not been a single accident due to fire or gas explosion at Pechelbronn, although in 1935 the total length of galleries amounted to 200 km.

Yield of Drainage.

Following our investigations in 1915 concerning the porosity of sand, we had expected that the quantity of oil remaining in a deposit after it had been worked by sinking and pumping would be $2\frac{1}{2}$ times as much as had been extracted. This estimate proved to be a fair one.

On the other hand, the extraction of the sand, especially washing with hot water, did not yield the desired quantities in practice. We had to be content with collecting the oil which flowed out in the galleries. This new method of extraction had the great advantage of cheapness.

As early as 1915 we had expected that a part of the residual oil would flow away by oozing in the galleries, but the results of our first years of working quite surpassed our expectations. The yield by drainage amounted to twice that given by sinking. At the end of 8 years working comparative figures for the two methods showed that in the long run results were approximately similar. From this fact it would appear that figures relative to Pechelbronn given prior to 1925 would make the drainage figures appear too high.

The relation between the production yields from boring and from mining cannot be exactly represented by means of figures.

Actually the quantities of oil produced by drainage will vary between once and twice that from boring, according to the original saturation of the rock, the composition of the sand, the dimensions, regularity, and stratification of the beds, their richness in gas and the gas pressure, the degree of fluidity of the oil, the presence or absence of water sands near the deposits, and the amount of residual oil in the deposits already worked by means of sinkings.

Conclusions.

In the course of 18 years the Pechelbronn mines have produced, by means of drainage from areas already exhausted by sinking, about 500,000 tuns of oil. The sinkings which worked light crude oil since 1882 have yielded in 54 years a total of about 1,500,000 tuns. The mean annual production would thus be the same for each method and would amount to 27,780 tuns.

This statistical comparison makes no difference to the value of the drainage yield mentioned, but the figures do show that there is still a large quantity of oil which might be extracted at Pechelbronn by means of wells and galleries. Nevertheless, it should not be imagined that drainage can be applied, any more at Pechelbronn than elsewhere, to all deposits. We can only consider those which sinkings have shown to be rich, of fair extent, and fairly accessible, especially those which are not water-bearing. In the parts of the Pechelbronn workings where the galleries are at depths of 150 to 400 metres the cost price of drained crude oil is rather higher than that of the oil obtained by sinking and pumping, but this slight difference is, in the main, compensated by the tax and customs protection enjoyed by the Pechelbronn mining concern. Quite apart from questions of money, the new method of working adopted in Alsace has succeeded in showing the importance of oil reserves remaining buried in deposits apparently exhausted by ordinary extraction methods.

MINING FOR ASPHALT

By A. LEAMON BERRY

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THE term 'asphalt' covers a wide field both in regard to the nature of the material and its natural occurrence. Asphalt may occur superficially or underground. It may take the form of sheets, dykes, or irregular veins, or it may be in a stratiform condition. Physically and chemically it may vary from a soft bitumen to what is virtually a rock in which the bitumen occurs merely as an impregnation.

As a characteristic example of a superficial deposit the Pitch Lake of Trinidad cannot be excelled. In this case the asphalt is really an intimate mixture of bitumen, silt, clay, and water, and it occupies a large basin of more than 100 acres in extent and 100 ft. in depth. The method used in mining this material is very primitive and, with the exception of transport, it is all hand labour. The consistency of the asphalt is such that it will bear the weight of a man, and it is broken out in large masses with a pick and loaded direct on to small trucks which run on a light decauville line. At the edge of the lake the asphalt is transferred to an inclined cableway which runs to the sea-shore. The rails of the decauville line gradually sink deep into the pitch if left undisturbed for a long period. They are therefore lifted and relaid periodically, and in that manner the whole of the surface of the lake is worked. The excavations left when the scene of operations is shifted after the periodic lifting and relaying of the line gradually fill by virtue of the plasticity of the material. The pitch is treated at a refinery on the shore before shipment, the surplus moisture and vegetable impurities being removed.

In the case of veins of asphalt the principles adopted are strictly comparable to normal metalliferous mining practice. Galleries are driven along the veins, either from the surface or from a shaft, and the material is stoped out underground. One of the main difficulties that arises in such work is the extremely variable thickness of the veins and their irregularity, although this is not always the case, as, for instance, in the Grahamite Vein in West Virginia. This vein has the form of an almost vertical infilled fissure in sandstone, a mile in length and varying in thickness from 2 in. at the ends to 6 ft. in the centre. As a mine it has long been abandoned. The Gilsonite deposits of Utah form another good example of this type of occurrence. Some of the longest veins have a length of more than 5 miles, and vary in thickness up to 18 ft., in fact, the Cowboy Vein maintains a thickness of 8 to 12 ft. for 4 miles. In mining these veins little timbering is required, the veins being nearly vertical whilst the sandstone and shale walls are firm.

The most important aspect of mining operations for asphalt refer more particularly to what should be termed asphalt rock. This is a natural product due to the impregnation of sedimentary rocks by bitumen and is found in two forms, one in which the rock is completely impregnated with bitumen and the other in which the penetration is irregular and the constituent grains have only a coating of bitumen.

From a commercial point of view rock asphalt must have a bitumen content varying from 8 to 13%. The thicknesses of the seams at present worked range up to 24 metres and are rarely continuously impregnated, being made up of layers containing different percentages of bitumen separated by layers of limestone free from bitumen. In some cases the rock asphalt is found at or near the surface, and the practice is to gain access either by open quarrying or by inclines or shallow adits.

In one particular case in Sicily where the seam is about 20 metres from the surface all this overburden is removed and the seam is worked on the quarry system, but such cases are rare. This method of exploitation has certain advantages, but is expensive and can only be used where the thickness of the asphalt is great and the beds are flat and near the surface.

More usually exploitation is carried out by running adits to meet the seam and then following the latter downwards by inclines. Limestone formations are proverbially noted for the magnitude of their water circulations, and water troubles therefore almost always intervene, necessitating the use of powerful dewatering pumps which have to be worked almost continuously. This is one of the main troubles in Neuchâtel, where all the deeper levels have to be continuously dewatered by supplementary pumps which lift water to the main pump level, where it is dealt with by the main pumping system.

Curiously enough, there are, as a rule, no dangerous gases in rock-asphalt mines, and therefore the use of naked lights is permissible. This is in marked contrast to the difficulties and dangers of mining for oil as carried out at Pechelbronn.

The general method of extracting rock asphalt is by drilling shot-holes, by hand or mechanically, of about 3 cm. diameter and about 1 metre 30 cm. long, into which the explosives are placed and tamped with rock powder. The explosive usually employed is black powder which has a less shattering effect than dynamite, cheddite, &c. This is essential as the asphalt rock can only be handled commercially in large pieces.

When the rock asphalt is brought to the surface it must be carefully sorted into its various grades and the poor quality layers eliminated. It is most essential to discard any clay as this is injurious to the uses for which rock asphalt is employed. This entails tedious and somewhat costly man-handling of the pieces of rock to chip away the clay. Sometimes there are small pieces of flint in the seam; these must likewise be removed with care or damage would be caused to the crushing machines, in addition to the disadvantage of including non-impregnated material in the commercial product.

The foregoing is a short appreciation of the main problems in the mining of rock asphalt where the exploitation is normally rather primitive and the mines are small. There is, however, one case of relatively deep mining in the Gard region of southern France. This will be dealt with in more detail as it is an excellent example of the general problems of asphalt mining and shows how these problems can be overcome by the application of modern technique. The mines are located at St. Jean de Maruéjols, where a series of highly impregnated Oligocene limestones, varying in thickness from 3 to 15 metres, outcrop on the eastern edge of a Tertiary basin near Alès. The rock asphalt is found and

worked at depths down to 300 metres, where it is overlain by a thick series of marly limestones and shales.

The rock asphalt was first found as a surface outcrop on the side of a hill, the beds dipping northwards at 15°. Exploitation was commenced by running adits at various levels into the seam and extracting the rock between the several galleries in sections of 10 sq. metres, leaving supporting pillars. These workings called for an elaborate system of propping, particularly as the asphalt was rich and the pillars would not support heavy overlying pressure. When the sections above the lowest adit level were worked out it was necessary to carry out downhill drives in order to extract from the deeper levels. Extraction costs increased owing to the haulage entailed, and conditions were aggravated by water troubles which would have meant a very costly installation of dewatering pumps at the bottom of the workings if the downhill drives had been continued. To obviate this a shaft some 60 metres deep was sunk to exploit the deeper rock asphalt, and dewatering pumps were installed at the bottom of this shaft. A main haulage gallery was made from the shaft bottom with a ½% slope to facilitate haulage and drain the workings back to the shaft bottom.

One difficulty involved was the extreme thickness of the seam of about 12 to 15 metres, which necessitated it being worked in three levels, access between which was obtained by horizontal drives.

The height of the main gallery is from 3 to 3½ metres, and the width is about 3 metres so as to allow for a double track of decauville lines. Off this haulage gallery inclines are driven at suitable points following the slope of the seam, which is about 15°. These inclines have the same section as the haulage gallery, and are also installed with a double track of decauville lines. As the slope of these galleries is fairly steep it is necessary to make special arrangements for the raising and lowering of the decauville wagons. The method employed is to install a horizontal pulley (fitted with a brake) round which runs a cable having at one end a counter-weight which runs on one of the decauville tracks. The weight of this counter-weight is made slightly less than a decauville wagon fully loaded with rock, which enables full wagons to descend gently and empty wagons to be hoisted up, thus avoiding the inconvenience and expense of mechanically driven winches. Off these inclines 'chantiers' or 'extraction chambers' are worked at right angles and on a slight rise on a width of 5 metres, leaving supporting pillars of about 2 metres square or even more, according to the condition of the roofing. To reduce to a minimum the necessity of shoring up with props, a wall of about 2 metres wide is made with the sterile and poor quality rock, which also avoids the necessity of bringing commercially useless rock to the surface. When the 'chantiers' reach the end of the concession the supporting pillars are pulled down, commencing at the end of the concession and working towards the shaft so as to obtain the maximum possible extraction of the asphalt seam.

Owing to structural anomalies in the life of the seam it is sometimes necessary to make a downhill drive from the main haulage gallery, but this is done as little as possible as it calls for a mechanical winch for the raising and lowering of decauville wagons, and as water is present it is necessary to install a dewatering pump to discharge the water up to the main haulage gallery.

During advancements 'faults' are met which throw the asphalt seam either upwards or downwards, necessitating a change of direction of the drive so as to strike again the same part of the seam. The throws of these faults have varied from 1 metre to 160 metres. Where the fault throwing the asphalt seam downwards 160 metres was met it was not practicable to make a downhill drive of this importance, so the seam was entered again by the building of a shaft some 280 metres in depth.

The drilling of the shot-holes was originally carried out by hand, but this was slow work as it took some 40 minutes to drill a hole of 1 metre 30 cm. in length. Numerous trials were made with electric drills, but owing to the excessive humidity in the workings there were constant break-downs of their electric motors. Good results were finally obtained with pneumatic rotary drills, the time taken to make a hole 1 metre 30 cm. long being reduced from 40 to 5 minutes. Tests were made with pneumatic percussion drills, but these were found unsatisfactory for rock asphalt.

As previously mentioned, black powder is the normal explosive. In these workings water is generally present in the shot-holes, which, acting on the black powder, reduces the explosive effect, but this has to a large extent been overcome by enclosing the powder in waterproof bags. Normally the charges are fired by a fuse, but where inflammable or explosive gases are present in the workings it is necesssary to use a detonator and fire the charges electrically. Another advantage of using black powder is that the gases given off are less obnoxious than with other explosives such as dynamite, enabling the miners to return to the face in a shorter time.

Black powder is replaced by cheddite, dynamite, &c., in the following cases:

1. Where the shot-hole gives appreciable quantities of water and renders the waterproof bags containing the black powder ineffective.
2. Where there exist numerous fissures in the seam allowing the gases from the explosion of the black powder to escape and so reduce the explosive effect.
3. When making advancements on a small section the superior explosive power of cheddite, &c., enables a surer and quicker advancement to be made than with black powder.

The method of ventilation is to allow sufficient air to pass down the working shaft and through the workings, the foul air passing out via a second shaft which is reserved solely for ventilation and as an emergency exit; this obviates the passage of gases up the working shaft deteriorating steel fittings, &c. The air circulation is assisted by an exhaust fan placed on the surface at the ventilation shaft, and suction fans are installed in the various headings to deliver fresh air and eliminate foul air from them. A series of doors is installed in the workings to ensure the most efficient flow of fresh air to the working sections and by-pass the worked-out portions of the mine, thus ensuring maximum efficiency of ventilation.

When first opening up the asphalt seam at some 280 metres below ground there was only one shaft, and ventilation of the workings was assured during the building of a second shaft by a suction fan fitted on the surface which drew the foul air from the workings by means of air piping. By this means the fresh air passed down the shaft, the circulation of air in the workings being assisted by fans which were moved as the advancements of the galleries were made.

In the early stages of exploitation down to 120 metres the greatest difficulty was in dealing with important water inflows which were found to be coming from open fissures in the asphalt seam and also in the formations immediately

above and below. At times, particularly after heavy rains, the inflow of water attained 800 cubic metres per hour, but after the carrying out of injections of cement the maximum inflow of water was reduced to 125 cubic metres per hour during rainy seasons and about 25 cubic metres per hour during dry seasons, when the hydrostatic level in the surrounding country fell and so reduced the water pressure. When the inflow of water was so large that it exceeded the capacity of the pumps at the bottom of the shaft the mine became flooded and in consequence the water rose up the shaft. During very heavy rainfalls, which are not uncommon in this region, it was necessary to decide whether the inflow of water would exceed the capacity of the pumps, and if this appeared likely then the electric motors of the pumps were dismantled and brought to the surface in order to avoid their being submerged, although this decision meant the temporary abandonment of the mine. Under these conditions dewatering could not be commenced until the hydrostatic level fell, or, in other words, until the inflow was less than the capacity of a dewatering pump, which had to be lowered in stages down the shaft until the workings were sufficiently dewatered and the electric motors could again be installed in the pump chamber. The dewatering of the shaft and workings by the lowering of the pump in stages down the shaft was very laborious, and then again the workings were sometimes flooded for several weeks whilst waiting until the inflow had reduced. These difficulties were overcome by isolating the shaft and pump chamber from the workings by strong masonry barrages and watertight doors. These barrages and watertight doors were fitted with sluice valves so that the water admitted to the pump sump could be regulated to suit the capacity of the pumps, so avoiding once and for all the pump chamber and shaft becoming flooded. This system also prevented the pumps becoming flooded in cases of serious break-down of the electric current, which at times occurred during heavy thunderstorms, which are not uncommon in this mountainous region, the supply being by overhead cable from a power station some 20 miles distant. Having overcome this great inconvenience careful studies were made with a view to reducing the water inflows to a strict minimum, as apart from their stopping extraction the costs of pumping were very heavy. It was observed that open water-giving fissures existed in the seam and also in the formation immediately above and below, so that when they were uncovered during extraction serious inflows of water under pressure into the workings took place. In some cases the water inflow met was around 100 cubic metres per hour. In order to avoid as far as possible the unexpected meeting of these water inflows, test holes for some 5 metres long were drilled into the seam and also into the flooring and roofing in all headings. When water was met by a test hole, preparations were at once undertaken to shut off this inflow by making an injection of cement, which was carried out in the following manner.

The test hole was immediately blocked by a lead plug and a second test hole commenced in a direction to meet the extremity of the first one. Into the second test hole a steel tube of about 5 cm. diameter fitted with a stopcock was fixed. The drill was passed through the stopcock and steel tube and the hole continued until the water was met. The drill being removed, water was allowed to pass through the stop-valve for about 15 minutes so as to ensure the hole being as free as possible of foreign matter, after which the stopcock was closed and connected up to a pressure pump. In many cases the fissures had very small openings and it required a high pressure for injecting cement into them. A pump capable of producing a pressure of 1,000 lb. per sq. in. was therefore used. The general practice was to pump clear water into the fissure for about 15 minutes so as to ensure as far as possible that the hole was free from foreign matter, after which a mixture of cement and water was used. From time to time clear water only was pumped into the fissure with the object of being more certain that the cement was being deposited at the extreme end of it. At the commencement of a cement injection a mixture of 7 to 8% of cement was used which was increased up to about 25% cement to water if the fissures would take it. The average weight of cement injected per hour was very variable, but can be taken generally as follows:

For fissures up to 5 mm. opening .	150–200 kilos.
„ „ 5 mm. to 10 mm. opening	250–400 kilos.
„ „ more than 10 mm. opening	500–600 kilos.

The only means of knowing when an injection was finished was by the pressure pump pulling up or a joint blowing out. In cases where the fissure took cement freely, dry fine sawdust was added to the cement-water mixture. It frequently happened when cementing up a water channel that leaks of cement came from small fissures in the vicinity, in which case fine dry sawdust was added to the cement-water mixture so as to shut off these local leaks and ensure as far as possible that the cement was deposited well into the water-giving fissures. When carrying out cement injections it is imperative that the pump and suction pipe are free from air and that the suction pipe is well covered with water during pumping. Cement injections should be carried out systematically and the injections continued without stopping until the water leak is completely blocked. Although these cement injections handicapped advancement and production, it is certain that from the results obtained their employment was necessary to enable exploitation to be continued. After stopping a water inflow by a cement injection it has been found, when a certain advancement has been made, that fissures of 5 mm. to 20 mm. openings were filled with cement, and in numerous cases where the seam was badly disturbed fissures as small as 1 mm. opening were cemented up. As an example of what can be achieved, a test hole discovered an inflow of water of 50 cubic metres per hour. Thirteen tons of cement were injected at this point, which stopped the inflow and also all the small leaks into the mine within a radius of 60 metres.

As another instance where an injection of cement was made it was found after advancing some 80 metres from the point of injection that a fissure existed in the flooring with an opening of 5 to 20 cm. on a length of about 65 metres. This fissure was completely filled with cement as also was the case with minor fissures in the close vicinity.

It frequently happened during advancements that fissures were uncovered which were not water-bearing, but as a precaution these were solidly cemented up. Another precaution taken was to install in all galleries leading off the main haulage gallery a strong watertight door so that in the event of important water inflows occurring in any of these workings they could be isolated, thus avoiding jeopardizing the other workings and making it possible for the water inflow to be dealt with at leisure. There were cases when excessive dripping of water occurred from the roofing, rendering the working conditions for the men almost impossible, so the roofing was lined with steel sheeting to divert the water to the sides of the gallery, but this was finally completely overcome by cement injections.

It has been explained previously that in the exploitation of rock asphalt up to a depth of 120 metres difficulties were met in contending with water inflows which came from open water-giving fissures, but as no inconvenient gases were encountered naked lights could be used. In exploiting the asphalt seam at 280 metres depth the water inflows were not appreciable and the fissures in the formation were generally in the form of hair cracks. Another trouble was, however, met in the form of firedamp and sulphuretted hydrogen. The presence of firedamp called for the use of safety lamps and special electric motors of the non-sparking type. The special precautions necessary for the firing of explosives has been referred to above. The presence of sulphuretted hydrogen was an inconvenience to miners as it caused considerable irritation of the eyes and throat, and where leaks of this gas occur the practice is to place quicklime in the vicinity of the leak in order to absorb as much as possible of the gas. As an additional precaution in zones where sulphuretted hydrogen is present the walls of the galleries are sprayed from time to time with sodium hypochlorite. Such leakages of gas generally cease after about 10 days, proving that they are local and in pockets in the formation, but meanwhile the withdrawal of the men from the zone of leakage is necessary.

SECTION 12

OILFIELD WATERS

METHODS OF ANALYSIS OF OILFIELD WATERS

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Collection of Water Samples from Wells.

THE collection of water samples from drilling wells [64, 72] is dependent upon the exigencies of drilling. In the case of high-pressure artesian water entering the well the bore-hole will be flushed clear of the drilling mud and samples may be taken at the surface. With percussion methods the hole should be bailed free of drilling water and the sample taken from the bottom by means of a bailer or sand-pump. In the case of rotary-drilled wells it is extremely difficult to avoid contamination with the circulating mud fluid, and the sampling of small 'water-shows' is frequently impossible, as they may not be observed, or may be quickly 'mudded-off'; with larger 'shows' a sample may be taken from the bottom by means of a bailer or sand-pump if drilling conditions permit, but frequently only a sample of the water arriving at the surface contaminated with drilling mud can be obtained. If the well is making gas it is necessary to guard against an increase in concentration, or the precipitation of salts from a saturated water due to the evaporating of water by the released gas. To minimize this effect the well should be controlled at the flowhead until a steady condition is attained and the water removed through a side-line. The sample taken should be sufficient to give two Winchesters of filtered water. The conditions of sampling may be indicated briefly by an arbitrary scale of reliability, using letters or numerals in order to indicate the importance of subsequent analyses. To provide a check in case of contamination, samples of the drilling fluid should be taken periodically.

Preliminary Treatment and Examination.

Suspended Matter [72, 95]. This must be removed before a quantitative analysis of the water is carried out. The water is passed as rapidly as possible to minimize evaporation losses through a large pleated filter-paper. If, after filtration, the water retains a faint opalescence, this minute colloidal suspension may be regarded as part of the dissolved solids. Oil is removed by a separating funnel, emulsions are centrifuged in the first instance, non-corrosive or glass apparatus should be employed, the Winchester or bottle should be capped and labelled with: Well No. Water No. Depth. Sp. Gravity. Formation. Date, and other relevant data.

All samples should be taken in duplicate.

Specific Gravity and Quantity taken for Determination of Various Ions.

The specific gravity of the filtered-water sample is usually determined by the Specific Gravity Bottle [113] or Westphal Balance and returned at 60° F. The determination should be carried out in the vicinity of 60° F., and the usual correction for variation of density of water with temperature applied [25]. From the specific gravity the volume of the sample taken for the determination of ions, or the necessary dilution of the sample can be ascertained very approximately from the table given by Reistle and Lane [72]. In certain cases it is preferable to ascertain approximately the relative amounts of the respective ions by a preliminary qualitative analysis. From this preliminary examination a volume of water can be estimated suited for either gravimetric or volumetric determinations.

Determination of Total Solids.

Determination of Total Solids [4, 20, 57, 90, 95, 96] is carried out by evaporating 100–500 ml. (according to the sp. gr.) in a weighed porcelain dish on a water bath and drying for one hour at 180° C. C. S. Howard [38] found that this method gave results reasonably close to the sum of the determined constituents for most natural waters. In the majority of water analyses the figure obtained is greater than the sum of the determined constituents due to the retention of water of crystallization, occlusion of water, and presence of small amounts of undetermined constituents; errors of opposite sign may be introduced by the volatilization of chloride in waters where the chloride is more than equivalent to the alkalis. Loss of chloride is not usually apparent because the amount of water retained by the residue is often greater than the chloride loss. Negative errors also arise in waters with a high nitrate concentration and in those of the carbonate type containing calcium, relatively large amounts of magnesium, carbonate, and bicarbonate. C. S. Scofield [82] and L. V. Wilcox [83] have estimated the total salinity of waters by determination of the specific conductance, which they multiply by a factor depending on the nature of the dissolved substances. G. Zinzalian and J. R. Withrow [107] ignite at 750° C. and correct for the volatilization loss according to a formula. Reistle and Lane [72], for waters with specific gravity greater than 1,025, calculate the total solids from the specific gravity according to the table published in U.S.B.M. Technical Paper 432.

GENERAL CHEMICAL ANALYSIS

The analysis [1, 58, 64, 72, 96, 98] involves the following sequence of operations: elimination of silica, iron, and aluminium; estimation of calcium, magnesium, sodium, potassium, and ammonium (Part I): estimation of chloride, sulphate, carbonate, bicarbonate, hydroxide, and ions of rarer occurrence (Part II).

Part I

Silica, iron, and aluminium [12, 33] are not estimated as a rule, but must be eliminated before the metallic ions are determined either gravimetrically or, in certain cases, volumetrically. The appropriate volume of sample which should leave on evaporation a solid residue of 0·4–0·6 g. is slightly acidified with hydrochloric acid evaporated to dryness, and the residue baked in an oven at 200° C. for 1 hour, or at 105° C. for at least 6 hours to render the silica insoluble. To the residue after digestion with 5 ml. conc. HCl, 50 ml. water are added and the mixture boiled (1 min.). The silica, together with insoluble silicates and other insoluble matter, is transferred to an ashless filter-paper, washed with water and rejected. To the filtrate a few drops of conc. HNO_3 are added, the solution boiled, evaporated if necessary to a volume of 100–150 ml. and

a slight excess of ammonia added, the solution being gently heated to remove excess of ammonia. The precipitate is discarded unless required for estimation of alumina and iron.

(In the estimation of the silica and insoluble residue, also alumina and ferric oxide, the respective precipitates are dried, placed in a muffle, and brought to the anhydrous condition by igniting for 1 hour at the full temperature attainable.

Iron may be estimated colorimetrically [39] in the original water by ammonium thiocyanate; should ferrous iron be present oxidation with nitric acid is necessary.)

Determination of calcium [33, 56, 97]. The filtrate and washings are concentrated if necessary to 200 ml. approximately; 10 ml. of 10% ammonium chloride are added and the solution, made alkaline with excess of ammonia, is brought to the boiling-point. Sufficient of a hot solution of 4% ammonium oxalate is added for complete precipitation of the calcium as oxalate, then 10 ml. excess are added. The precipitated calcium oxalate is boiled for 2–3 minutes, allowed to settle on a hot plate for about an hour, and then filtered. This method precipitates all but a mere trace of calcium and the precipitate is for all practical purposes free from magnesium provided that a greater quantity of magnesium than the ratio 1 Mg : 1 Ca [11, 40, 73] is not present in the solution, a condition rarely encountered in oilfield waters. The precipitate is washed with hot water and estimated either gravimetrically or volumetrically.

Gravimetric. The oxalate is converted to oxide after the paper with adhering precipitate has been first incinerated. Ignition in a muffle at 1,050° C. for approximately 1 hour or at 1,200° C. for 5 minutes converts the oxalate completely to oxide [33, 97].

Volumetric. The filter-paper is punctured and the precipitate is washed into a beaker containing dilute sulphuric acid with warm water. The filter-paper is then treated alternately with warm dilute sulphuric acid and warm water, 100 c.c. of dilute sulphuric acid of strength 1 conc. acid : 10 water being employed for the determination. The liquid is gently warmed until decomposition is complete and then titrated at 70° C. with 0·1 N. $KMnO_4$. As soon as the permanent end-point is reached the punctured filter-paper is transferred to the beaker and agitated with the solution. Should the pink colour be discharged, incomplete washing of the filter-paper is indicated; only a few drops of $KMnO_4$ should be necessary to restore the permanent pink colour of the end-point [40].

A. C. Shead and his collaborators [87, 88] describe a method for separating calcium and magnesium by the formation of soluble mono-calcium saccharate; P. L. Kirk and E. G. Moberg [43] give a micro-chemical method for the determination of calcium in sea-water, and R. C. Wiley [104] separates calcium by precipitation as calcium molybdate and estimates magnesium in the filtrate with ammonium phosphate.

Determination of magnesium. *Gravimetric* [21, 60]. The filtrate containing approximately 0·06 g. of magnesium is evaporated until a pasty residue is obtained; the dish is covered with a clock glass, 10–12 ml. nitric acid (sp. gr. 1·4) are added, and heating is continued until the ammonium salts have been decomposed. The residue, dissolved in water, is acidified with 5 ml. concentrated hydrochloric acid and diluted to 150 ml.; 10 ml. of a saturated solution of diammonium hydrogen phosphate are added and the solution, with constant stirring for 5 minutes, is brought to neutralization point by addition of concentrated ammonia. An additional 5 ml. of concentrated ammonia are added and the solution stirred periodically during 10 minutes. After standing overnight (4 hours as a minimum) the precipitate is filtered off and washed with ammonia solution (3–5% of 0·880 ammonia). No reprecipitation is necessary under these conditions. The precipitate, after drying, is ignited and estimated in the usual way.

Volumetric. To the original water, ammonium chloride, ammonium hydroxide, and ammonium carbonate are added as in the usual qualitative procedure for the separation of metallic ions. The mixture is warmed, filtered, and the filtrate and washings made up to volume so that 50 ml. contain 0·02 g. magnesium approximately. Precipitation is carried out near the boiling-point by adding a 2% alcoholic solution of 8-hydroxy-quinoline [10, 31, 37] in slight excess, or an acetic acid solution of the reagent may be used. The precipitate is filtered on to a Gooch crucible, washed with water (15–20 ml.), dissolved in as small a quantity as possible of 5 N. HCl, and the solution made up with distilled water to 2 N. HCl approximately. The 8-hydroxy-quinoline is brominated quantitatively by excess of 0·2 N. bromide-bromate solution [35], which excess is determined by addition of 10% potassium iodide solution and titration of the liberated iodine with sodium thiosulphate.

One milligram is equivalent to $2C_9NH_6OH$, which is equivalent to 8 Br. Calcium, if present, gives a positive error which can be eliminated by reprecipitation of the magnesium-8-hydroxy-quinolate, or calcium may be separated first as described above. K. V. Luck and H. J. Meyer [56] estimate calcium as oxalate and magnesium as 8-hydroxy-quinolate: further, M. E. Stas [91] gives the conditions for accuracy of this method.

Estimation of sodium. (*a*) *Zinc uranyl acetate method* [7, 45, 99]. The original filtered water can be used, the sodium concentration should lie between 2·5 and 40 g. NaCl per litre. Five millilitres of the neutral water, 15 ml. distilled water, and 85 ml. of zinc uranyl acetate reagent are put into a small beaker and allowed to stand 1 hour. (For concentrations of sodium between 2·5 and 10 g. NaCl per litre, 5 ml. neutral water, 5 ml. distilled water, and 25 ml. of reagent should be used.) The precipitate is filtered on to a Gooch crucible, porosity B_1 or B_2, drained and washed with 20 ml. of absolute alcohol saturated with sodium zinc uranyl acetate. The acetate radicle is eliminated by warming with 5 ml. 60% H_2SO_4 for 1 hour or until no odour of acetic acid is discernible. The residual liquor is washed through a Jones reductor [33, 61] with 100 ml. water, and any tervalent uranium present is oxidized to the tetravalent state by bubbling air through the solution for 10–15 minutes. The reduced solution is titrated with 0·1 N. $KMnO_4$ and the usual end-point colour correction applied [33].

$$1\ \text{Na} = 3\text{U in the triple acetate.}$$
$$\frac{\text{U}}{20} \simeq 1{,}000\ \text{ml. } 0{\cdot}1\ \text{N.}KMnO_4.$$
$$1\ \text{Na} = 60\times 1{,}000\ \text{ml. } 0{\cdot}1\ \text{N. } KMnO_4.$$
$$\frac{23}{60\times 1{,}000}\ \text{g. Na} = 1\ \text{ml. } 0{\cdot}1\ \text{N.}KMnO_4.$$

Magnesium and calcium in small concentrations [99] do not interfere, but in the presence of ammonia, free or combined, large negative errors result.

Zinc uranyl acetate reagent:

Solution A		*Solution B*	
Uranyl acetate A.R. .	85 g.	Zinc acetate A.R. .	200 g.
Acetic acid glacial 98%	50 ml.	Acetic acid glacial 98%	25 ml.
Distilled water . .	400 ml.	Distilled water . .	250 ml.

The solids are dissolved by heating each solution to 70° C., the solutions are mixed, cooled, and filtered.

(*b*) *Dihydroxytartaric acid method* [71]. The filtered original water is treated with ammonium chloride, ammonium hydroxide, and ammonium carbonate for the removal of all metallic ions except magnesium and the alkalis, then the filtrate is evaporated to a pasty residue and concentrated nitric acid added (cf. magnesium). The residue is dissolved in sufficient water to bring the sodium concentration within the range 20–40 g. NaCl per litre. To 5 ml. of the resulting solution, 5 ml. 20% dihydroxytartaric acid, 5 ml. K_2CO_3 solution (153·9 g. per litre), and 35 ml. distilled water are added and the mixture allowed to stand at 5° C. for 4½–5 hours. The precipitate is filtered on a small perforated disk covered with two filter-papers, washed with 10 ml. ice-cold water, and transferred to a flask containing excess of potassium permanganate acidified with sulphuric and phosphoric acids and 2 ml. fresh 0·05% ammonium metavanadate solution. The volume is made up to 350 ml., allowed to stand 20 minutes, warmed to 52° C., and the excess potassium permanganate titrated with standard oxalic acid. It is necessary to apply a positive correction of 5 mg. Na in each determination for the above concentration range:

$$1{,}000 \text{ ml. } 0{\cdot}1 \text{ N.KMnO}_4 = \frac{0{\cdot}1 \times 2 \times 23}{6} \text{ g. Na.}$$

Estimation of potassium [19, 100]. To 5 ml. of water containing potassium in the concentration range corresponding to 10–40 g. KCl per litre is added 5 ml. distilled water and 25 ml. of a 10% solution of sodium 5-nitro-6-chloro-meta-toluene sulphonate and allowed to stand at 15° C. for 1 hour. The precipitate is separated on a Gooch crucible, porosity B_1 or B_2, and washed with 10 ml. of water.

For the *colorimetric* procedure the precipitate is dissolved in hot water and an aliquot portion (containing approximately 15–25 mg. of potassium) taken, acidified with dilute sulphuric acid, and the nitro group reduced by passage of the solution through a Jones reductor. The reduced solution is diazotized, coupled with alkaline R-salt, and the resulting colour compared in a tintometer (Lovibond) with standard glasses or in Nessler glasses containing known amounts of potassium. To obtain concordant results it is necessary to keep the alkalinity of the solution constant. For this concentration range the error is −8%.

In the *volumetric* procedure the precipitate is transferred to 50 ml. freshly boiled distilled water and 5 ml. conc. HCl; 40–50 ml. 0·5 N. $SnCl_2$ solution [42] are added and the mixture heated on a water bath for ½ hour, the whole operation being carried out in an atmosphere of carbon dioxide. The excess stannous chloride is titrated with 0·1 N. I_2 solution. A blank experiment under exactly the same conditions is carried out simultaneously. For this concentration range the error is −7 to −8%.

$$1 \text{ ml. } 0{\cdot}1 \text{ N. I}_2 \text{ solution} = \frac{39{\cdot}10}{60} \times \frac{1}{1{,}000} \text{ g. K.}$$

In addition, potassium may be estimated by means of conversion to potassium perchlorate [97] or potassium cobalti-nitrate [61, 110], or potassium chloro-platinate [97], or a combination of the latter two methods [109].

Estimation of ammonia. Ammonia in small amounts is a common constituent in natural waters. Free and combined ammonia are estimated by distillation without and with [22] the addition of alkali, the distillate being maintained slightly on the acid side by simultaneous titration with standard acid, using brom-phenol blue as indicator. F. L. Bassett [8] determines free and combined ammonia by steam distillation of the water sample into standard acid. Public Health authorities [39, 96] distil 500 ml. of the water with 1 g. pure sodium carbonate, the distillate being collected in 50 ml. fractions in Nessler glasses. Distillation of the free and combined ammonia is complete in the first 200 ml., the majority being in the first 50 ml. The amount of ammonia in each fraction is determined colorimetrically by adding Nessler's reagent. It is difficult to match accurately colorations deeper than that given by 0·000125 g. NH_3 as ammonium chloride in 50 ml.

Part II

Determination of acidity [72]. The acidity of natural waters is due to the presence of mineral acids [85], mineral acids derived from the hydrolysis of salts of weak bases and strong acids, carbonic acid, and hydrogen sulphide. The determination of free mineral acid [1] is carried out by titrating a definite quantity of water with 0·1 to 0·01 N. NaOH, using methyl orange as indicator. Carbonic acid may be determined by neutralizing to the half-way stage using phenolphthalein as indicator, but owing to the hydrolysis [44, 84] of the acid sulphides, phenolphthalein does not indicate the half-way stage of the neutralization of hydrogen sulphide by caustic soda. The determination of acidity by alkalimetry is of little value in the classification of waters, and greater importance is attached to the determination of the hydrogen-ion concentration. The usual method is to determine the approximate *pH* of the water by the use of a universal indicator, the exact *pH* being subsequently determined by the method described by S. W. Cole [16], I. M. Kolthoff and N. H. Furman [47], Thresh and Beale [96]. The procedure merely consists in comparison of the water with a reference solution of known *pH* to which a suitable indicator has been added. This determination enables waters to be divided into the following groups:

(1) *pH* under 4·5. The water contains free mineral acid, carbonic acid, hydrogen sulphide, or combinations of these acids. Such waters contain neither carbonates nor bicarbonates.

(2) *pH* range 4·5 to 8. Such waters may contain free carbonic acid, carbonic acid, and bicarbonates; hydrogen sulphide, hydrogen sulphide and acid sulphide. Most natural potable waters are buffered with $CaH_2(CO_3)_2$ and H_2CO_3, so their *pH* lies between 7 and 8. In soft waters the presence of organic acids changes the *pH* to 5 or even below.

(3) *pH* over 8. The water contains no free carbonic acid or hydrogen sulphide, but may contain carbonates, hydroxides, and normal sulphides or bicarbonates in the presence of carbonates, or acid sulphides alone or in the presence of normal sulphides, or combinations of these.

The acidity of the water is reported as the equivalent amount of $CaCO_3$ in parts per million or simply as the *pH* value.

Hintz and Gronhut [36], also Auerbach [5], have calculated the hydroxyl-ion concentration of alkaline water from the carbonate and bicarbonate content; L. Michaelis [60] has examined the *pH* value of certain mineral waters electrometrically. E. B. Powers [70] gives a colorimetric method for the field determination of carbon dioxide, bicarbonates, and carbonates by means of the hydrogen-ion

concentration before and after aeration with air of known carbon dioxide content.

Determination of hydroxide, carbonate, and bicarbonate [1, 72, 89, 98]. Natural waters may contain these ions separately or carbonate and hydroxide or carbonate and bicarbonate.

Qualitative tests. On the addition of 4 drops (0·2 ml.) of a 1% solution of phenolphthalein to 50 ml. of the water, a pink coloration is produced in the presence of carbonate or hydroxide. On the addition of 2 drops of phenolphthalein to 100 ml. of the hot water which has been treated with 20 ml. of 0·5 N. barium chloride solution, a permanent pink coloration is produced in the presence of hydroxide. If the latter solution is colourless and remains colourless on the addition of 1 drop of 0·1 N. NaOH, the presence of bicarbonate is indicated.

Quantitative determination. To an appropriate quantity 2 drops of a 1% solution of phenolphthalein are added and titration is carried out with the tip of the burette immersed under the water which is given a gentle rotary movement until decolorization of the indicator occurs. Two drops of a 0·1% solution methyl orange are added and titration continued until the intermediate colour-change is obtained. The acid used should be approximately 0·1 N. HCl, standardized against sodium carbonate solution with the above quantity of methyl orange indicator.

The phenolphthalein-methyl orange method as described above has been criticized by W. C. Schroeder [79, 80, 81] and E. P. Partridge and W. C. Schroeder [66], who have found it to be inaccurate for solutions with carbonate concentrations less than 60 parts per million. At these low concentrations the inflexion-point of the titration curve occurs at higher *pH* than the *pH* of the methyl orange end-point. This author suggests the use of an indicator which is sensitive for colour change at a higher *pH* and the use of accurate colour comparison blanks. The Winkler method [52, 55] for the determination of the carbonate and hydroxide concentrations consists in titration of a sample with phenolphthalein; a second sample is then taken, the carbonate precipitated by barium chloride, and the solution titrated with phenolphthalein. The second titration is equivalent to the hydroxide concentration, and the difference between the two titrations is equivalent to the carbonate present. Schroeder found this method to be inaccurate in the presence of sulphate [92] owing to the adsorption and occlusion of the hydroxide. Thresh and Beale [96] describe a simple titration method using methyl orange (for CO_3) but without differentiation of hydroxide, carbonate, or bicarbonate. F. G. Straub [92] discusses the accuracy of the American Public Health Association (use of phenolphthalein and methyl orange) and Winkler methods, and inaccuracy of the *pH* value for the determination of hydroxide, the conditions for accuracy of the A.P.H.A. method for carbonate, and concludes that the carbon dioxide evolution method gives the most reliable results for carbonate.

Determination of sulphate. *Gravimetric* [33, 97]. An aliquot portion containing sulphate radicle equivalent to 0·4–0·5 g. $BaSO_4$ as a minimum is evaporated and treated for the removal of silica [cf. 115], insoluble matter, and iron and aluminium, as described in Part I. The filtrate and washings, which should measure 100–150 ml., are acidified with 5 ml. conc. HCl and heated to boiling; a hot 10% $BaCl_2$ solution is added with constant stirring in such quantity as to provide a 4–6 ml. excess, and boiling is continued for 5 minutes. The solution is digested just below the boiling-point for about an hour and allowed to stand in a warm place for 18 hours before filtering. The precipitate is filtered off on a No. 42 Whatman filter-paper and washed with hot water. The moist barium sulphate, together with filter-paper, is ignited at the mouth of a muffle furnace (approx. 900° C.). If impurities such as silica, alumina, or ferric oxide are present, decomposition occurs at 1,000° C. approx. with liberation of SO_3; or the precipitate may be filtered in a Gooch crucible, dried initially at 100° C., subsequently at 110–120° C. to constant weight.

S. Popoff and E. W. Neuman [69] recommend the addition of the sulphate solution to acidified barium chloride as a general procedure, and state that the usual method gives results which are much lower than the theoretical, the lower results being attributed to the preferential adsorption of the sulphate ions rather than the chloride ions.

In an exact determination a correction should be made for the solubility of the barium sulphate [17], the solubility of which increases with increasing concentration of hydrochloric acid.

Volumetric. The methods suggested for the determination of sulphate may be divided into three groups: (*a*) precipitation and filtration methods [41, 97], (*b*) titration methods, with and without an internal indicator [78], (*c*) turbidimetric methods [65, 96]. Of the filtration methods the benzidine process has been investigated extensively, and the conditions for accuracy are known.

To 120 ml. of the water, or such quantity which when evaporated to 120 ml. contains a concentration of sulphate radicle above 0·04%, 120 ml. of benzidine hydrochloride solution are added, 5 ml. at a time with stirring (6·7 g. benzidine dissolved in water with 20 ml. conc. HCl and made up to 1 litre). After 10 minutes the precipitate is filtered on a small porous disk covered with two filter-papers, and is washed with 15 ml. water. The precipitate, disk, and filter-papers, together with 50 ml. water are titrated at 50° C. with 0·1 N. KOH, using phenolphthalein. The method cannot be adopted in the presence of magnesium, tervalent iron, and aluminium. The two latter can be removed by the usual process and the former by precipitation as magnesium ammonium phosphate; thus the method can be applied to the filtrate so long as the concentration of neutral salts is not high; moreover, the phosphate radicle does not interfere. W. C. Schroeder [78] describes a direct titration method using tetrahydroxyquinone as internal indicator, and claims an accuracy within $\pm 0{\cdot}2$ mg. of SO_4.

Several methods [30, 76, 103] involving the use of barium chromate as precipitating reagent have been investigated. J. R. Andrews [3] precipitates the sulphate ion by addition of barium chromate solution, the excess of which is precipitated by ammonia, and estimates the soluble chromate by means of ferrous ammonium sulphate and potassium permanganate; this method, due to Hinman [34, 97], is applicable to oil-well waters whose sulphate content varies considerably, and may be employed in determining 2–200 mg. of sulphate. Hydrogen sulphide, ferrous iron, and other reducing agents should be oxidized before addition of the barium chromate reagent. A. Chalmers and G. W. Rigby [15] give a titration method using barium chloride and sodium carbonate. V. R. Damerell and H. H. Strater [18] use a standard solution of barium chloride for precipitating the sulphate radicle with mercuric nitrate as external indicator and discuss the conditions for accuracy of the titration. Several methods have been suggested as turbidimetric estimations, but, in general, investigators are

not in good agreement as to the relative accuracy of their methods. D. Northall-Laurie [63] uses a suspension of barium carbonate, and H. Fehn, G. Jander, and O. Pfundt [26], and I. M. Kolthoff and T. Kameda [48] give details of conductometric methods for evaluating the sulphate radicle.

Determination of chloride [33, 72, 97, 114]. The concentrations of chloride and sodium in natural waters usually so greatly exceed those of other ions that slight errors in their determination seriously affect the hypothetical ionic combinations. It is therefore necessary to determine the chloride ion with accuracy. The methods usually adopted are (*a*) direct titration with standard silver nitrate solution of the neutral water sample using potassium chromate as internal indicator, (*b*) direct titration with silver nitrate and potassium chromate after neutralization of the free acid with calcium carbonate, (*c*) Volhard's method, (*d*) gravimetric determination as silver chloride.

A rough titration of the water should be made, the dilution if necessary ascertained to adjust the concentration to 0·03–0·1 N. NaCl, and a corresponding quantity 75–25 ml. of the water titrated with 0·1 N. $AgNO_3$, using 1 ml. of 1% K_2CrO_4.

For dilute solution below 0·03 N. NaCl, a preliminary titration of the water with 0·01 N. $AgNO_3$ is essential to determine the approximate chloride concentration. Into a porcelain dish is placed the equivalent amount of a standard sodium chloride solution diluted to the same concentration as the water, 1 ml. of 1% K_2CrO_4 and 0·01 N. $AgNO_3$ equivalent in amount to the sodium chloride present; the titration is now continued to a permanent red colour and this latter quantity of silver nitrate noted. In a similar manner the natural water is titrated to precisely the same colour and the end-point colour correction applied. The procedure should be carried out speedily in absence of direct sunlight.

The above procedure is only applicable to neutral waters: should the water be acidic, calcium carbonate free from halogens is added in excess and the titration with silver nitrate carried out as described. Carbonates and hydrogen sulphide react with silver nitrate, and may be eliminated by boiling with a few drops of concentrated nitric acid.

Volhard's method [97] is applicable to acid waters: To 100–200 ml. of the water containing approximately 0·1 g. chloride ion, acidified with dilute nitric acid, not more than 5 ml. excess of 0·1 N. $AgNO_3$ is added and the precipitate coagulated by warming and shaking. The silver chloride may be filtered off and the filtrate and washings titrated with 0·1 N. KCNS, using ferric alum as indicator. If a weighed Gooch crucible is used for filtration, this procedure can be combined with the gravimetric method [62] by weighing the precipitated silver chloride. Volhard's method is satisfactory for the above concentrations of chloride ion, but for smaller concentrations the results are high. High concentrations of sulphates interfere, sulphate being carried down as silver sulphate in the thiocyanate precipitate (cf. Comey and Hahn, *Dictionary of Chemical Solubilities, Inorganic*, 2nd ed. 1921, p. 1013, for solubility of silver sulphate in water and dilute nitric acid). Mason and Buswell [58] recommend the use of yellow glass for determining with accuracy the appearance of red silver chromate. In Mohr's method [97] dichlorofluorescein, tartrazine, and phenosafranin [9, 49] may be used as adsorption indicators for chloride; for argentometric titration of chloride, both alone and in presence of iodide, Pieters [68] has found certain adsorption indicators—Victoria violet, chrome-green-G, &c.—satisfactory. The titration of ammoniacal solution of silver chloride by potassium cyanide using potassium iodide as indicator has been described by J. S. Pierce and J. L. Coursey [67].

Essential points with regard to the gravimetric determination of the chloride ion are (*a*) precipitation under conditions given under the Volhard method, (*b*) washing twice by decantation with hot 2% nitric acid before transference to the Gooch crucible, (*c*) washing with hot water and finally with alcohol, (*d*) drying at 130° C. to constant weight (3–4 hours approximately). As a rule the gravimetric procedure gives the higher results owing to adsorption by silver chloride of other salts. When increasing concentrations of pure sodium chloride are precipitated, the positive errors in the gravimetric results increase logarithmically in accordance with the adsorption isotherm.

Determination of iodide. The usual method is to evaporate 1–2 litres of water to approximately 200 ml. and to oxidize the iodide ion to iodate in sulphuric acid solution by excess of either (*a*) chlorine [2, 59, 105, 106], (*b*) bromine [74, 77], or (*c*) sodium hypochlorite; in the case of (*c*) 40–60 ml. of 42% phosphoric acid are used. The excess of oxidizing agent is removed by boiling; 1% KI is then added in excess and the liberated iodine titrated with 0·005 N. $Na_2S_2O_3$. The iodine estimated corresponds to 6 times the amount of iodine present in the original water. J. S. Parker and C. A. P. Southwell [64] give a standard iodine test (worked out by the Shell-Mex Central Laboratory) in which the iodine present in the water (evaporated down to a definite volume and acidified) is oxidized by hydrogen peroxide, and the liberated iodine, dissolved in chloroform, is estimated either by thiosulphate titration or colorimetrically against iodine-chloroform solutions. Other methods of importance for the estimation of iodide are determination by means of (*a*) potassium permanganate [32], (*b*) ceric sulphate [93], (*c*) use of adsorption indicators, which have been introduced by Fajans and his collaborators [23, 24], Kolthoff and his collaborators [46, 51], and Lang and Messinger [54], but as far as is known these methods have not been applied to oilfield waters. M. Settimj [86], using a micro-method, indicates that titration of iodine with sodium thiosulphate gives satisfactory results if the dilutions of the two solutions are not greater than 0·002 N.

Estimation of fluoride. It is claimed that an adaptation of the volumetric thorium precipitation method [94] is most satisfactory for the quantitative estimation of fluorides in natural waters [13]. The colorimetric methods adopted depend on (*a*) [28] the intensity of the colour produced by ammonium thiocyanate with a given amount of iron in the presence of fluoride, (*b*) the use of zirconium nitrate-sodium alizarin sulphonate indicator [14, 75], (*c*) the use of zirconium purpurin reagent [50].

Estimation of hydrogen sulphide [1, 96, 97, 112]. Hydrogen sulphide occurs frequently in the waters of petroliferous regions; its odour renders detection easy; should a quantitative estimation be desired the sample is analysed immediately owing to the volatile character of the gas and its easy decomposition on exposure. For quantitative estimation a definite volume of the water is run into a measured quantity of 0·01 N. I_2 and 20 ml. of 10% KI acidified with sufficient 0·1 N. HCl to render the whole solution distinctly acid. The quantity of hydrochloric acid added should be sufficient to neutralize hydroxide and decompose carbonates and hydrosulphides if present. The excess of iodine is titrated with 0·1 N. $Na_2S_2O_3$. This method gives the total

hydrogen sulphide, normal and acid sulphides present in terms of hydrogen sulphide.

C. E. Lachele [53] suggests that minute amounts of hydrogen sulphide may be estimated by the passage of a current of nitrogen through the acidified solution, interaction of the evolved hydrogen sulphide with lead acetate paper, and comparison of the stain formed with stains given by standard concentrations of sulphide. Hydrogen sulphide may also be estimated by titration, or colorimetric comparison, of the precipitated cadmium sulphide obtained by passage of nitrogen through the boiling acidified water and absorption of the evolved hydrogen sulphide by an ammoniacal solution of cadmium acetate [6].

Estimation of nitrate [95, 96]. Most natural waters have usually only small quantities of nitrate present, which may be estimated by phenol disulphonic acid and the usual reduction methods.

Estimation of boron. Salts of boron which occur in most of the surface and underground waters of Southern California are estimated by formation of methyl borate [101, 111] and quantitative determination. F. J. Foote [27] determines boron in waters by titrating to a definite *pH* before and after the addition of mannitol. A further quantitative method is the adaptation of the qualitative turmeric test [29]; L. V. Wilcox [102] describes an electrometric titration for boric acid.

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THE INTERPRETATION OF OILFIELD WATER ANALYSES

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In recent years the importance of a knowledge of the analyses of underground waters to the petroleum engineer has been more and more evident. Waters in the strata through which the oil-well is drilled can seriously interfere with the production of oil. Waters (or as they should be termed, brines) are usually present in the oil sand itself occurring below the oil and gas, or in separate sands above, below, or intermediary between oil sands. The productivity of an oil sand can be greatly decreased by the presence of water, and lifting costs of the oil increased. Again, the presence of water in crude oil can cause the formation of emulsions of great persistence requiring special treatment for their breaking down.

Water associated with the oil in the same sand is referred to as edge water. Waters from other sands above the oil sand are known as top waters or, with more than one oil sand, intermediary waters. Bottom waters are those in sands below the oil sand.

There is now a recognized need for an accurate knowledge of subsurface conditions, and, on drilling a well, all waters encountered should be sampled, analysed, and recorded with their depth stated. Although such waters will be shut off, there is still a possibility of leakage later in the life of the well. Waters, or mixtures of two waters, thus leaking into a well can be identified by their analyses, if such records are kept.

Waters encountered in the various sands may differ sharply in their relative content of the individual dissolved mineral constituents, or in some cases such waters may only differ slightly from one another in the relative proportion of the various constituents, though more in their concentration.

There is a possibility that the chemical constituents of the same water may change over an area, but within a restricted area such variation is usually only slight. It will thus be seen that, considered locally, the individual water sands may be identified by the analysis of the water they contain, and this can be of value in the further development of the field.

J. S. Parker and C. A. P. Southwell [6, 1929] summarize the value of the chemical investigation of the character of oilfield brines within the series of strata, from which oil is produced, as follows.

1. Estimates can be made of the probable horizons at which salt-water-bearing strata may be expected, and mechanical programmes arranged accordingly.

2. In areas where zonal fossils or typical rocks are not available, the correlation of salt-waters may afford additional evidence in the interpretation of the subsurface structure.

3. The source of salt-water, which may subsequently break into the well, may be determined. Water entering a well might be a mixture of two waters and, from analyses, a simple calculation would show the proportions of the two components.

4. The distribution of similar type waters may be determined as an aid to the elucidation of the extent and trend of porous sand formations, so that a more accurate idea may be obtained of the subsurface conditions from an oil accumulation standpoint.

Besides methods involving the comparison of analytical data, the identification of underground waters has been attempted in other ways, for example, by the use of dyes, by the measurement of the water temperature, or by the determination [7, 1933] of the conductivity of the water. Some oilfield waters are coloured, due to contents of salts of naphthenic acids or other organic compounds. Parker and Southwell point out that the majority of Trinidad well waters range in colour from pale yellow to dark red brown, but that sufficient work has not yet been carried out to decide if the colour of a water is of definite value for correlation purposes. It is now almost universally agreed that reference to analytical data is the most reliable means of identifying a water, but, of course, such information could not be regarded as infallible. Cases have been noted where two different waters had similar chemical analysis.

Some limitations of water analyses as a guide to underground formations have been pointed out by E. K. Soper [12, 1932].

The underground waters encountered in formations associated with oil or gas are usually very saline, and in some cases the waters are practically saturated with certain mineral substances. Much of the work on oilfield waters has been concerned only with the major constituents and has ignored the traces of rarer substances. It may be that the much more complicated technique of analysis to embrace these minor constituents would be justified, but there is not sufficient published material on which to decide this point. Colloidal substances such as hydrated oxides of iron, aluminium, and silicon are usually removed from waters before analysis.

The alkalis, sodium and potassium, are usually the main metallic constituents of oilfield waters, and these are found abundantly in the deeper waters and may be of oceanic origin. Calcium and magnesium are also to be found in underground waters. In surface and shallow waters the content of calcium and magnesium may exceed that of the alkalis. Of the acidic radicals, sulphates are characteristic of surface and many underground waters, and these with the chlorides contribute the property of salinity to solutions. Chlorides are found in deep and sometimes in shallow waters. The presence of chlorides can be due to the contact of underground waters with salt deposits or possibly to an oceanic origin, i.e. connate water (fossil sea-water); however, the origin of concentrated chloride brines, not closely associated with salt deposits, is not fully known [11, 1933]. The sulphate content of underground waters has been shown often to decrease with the proximity of petroleum, but as oil in quantities not of commercial importance has been found associated with water deficient in sulphates, this deficiency in sulphates in underground waters cannot always be taken as evidence of the proximity of large petroleum deposits. The deficiency of sulphates in oilfield waters has been attributed to chemical action of the sulphates with hydrocarbons, but evidence is rather scanty. An alternative cause of this sulphate deficiency is to be found in the discovery of E. S. Bastin [2, 1926] of the presence of sulphate-reducing bacteria in oilfield waters. Carbonates and bicarbonates are common in many underground waters including those associated with

oil; sulphides, chiefly as hydrogen sulphide, also occur in many waters.

The occurrence, circulation, and nomenclature of oil-field waters have been well described by A. W. Ambrose [1, 1921] and C. E. Reistle [8, 1927]. Underground waters lie usually in well-defined beds of porous nature, usually sandy formations. The movement of water in these formations is influenced by such factors [5, 1923] as the size of grain, porosity, hydrostatic pressure, and the structural conditions. The pressure of such waters may be due to earth pressure, gas pressure, or usually hydrostatic due to the water entering the formation at a point higher than its underground position. Tightly packed formations, for example, clays, offer resistance to the movement of underground waters.

In the drilling of an oil-well, 'top water' sands are shut off by cementing the casing, or by the use of mud fluids or by the use of a formation shut-off. If these waters had been properly sampled and analysed, they could be identified if later they found their way into the well by way of a defective shut-off or from the oil sand through a neighbouring well.

Reistle summarizes the ways in which water may enter the well: by leaks in the casing due to corrosion, splits, loose couplings, or line cuts; incorrect placing of the water shut-off; or from leaks around the casing-shoe. Bottom waters may enter a well through a leaky plug or may emanate from a faultily drilled well in the neighbourhood.

In the oil sand itself, water is sometimes found at the base of the sand, though, usually, a thin impervious stratum separates it from the oil. In correlating the water sands passed through with known water sands in the neighbourhood, while drilling, occasionally lenticular and discontinuous water sands may be encountered of which there were no indications in other wells.

Sampling should be carefully carried out when samples of waters are needed for analysis. In cable-tool drilling the well must be bailed so that the incoming water is free from the drilling water. Bailing is necessary also in rotary drilling, so that the mud fluid does not contaminate the incoming water.

Methods of Recording Oilfield Water Analyses

The methods for recording oilfield water analyses put forward are to some extent empirical. The chemical nature and usual high concentration of saline constituents make it of some difficulty to record the proportions of dissociated and undissociated salts present. In this connexion the paper of D. S. McKinney [4, 1931] on the equilibrium considerations, determining activities, and concentrations of ions is of interest.

The results of water analyses can be submitted in one of the following three systems: as proportions of chemical compounds (which may be hypothetical if the salts are completely or partially ionized), the Stabler-Palmer system of character formula, or with each radical or ion expressed in parts per million.

Such systems are well described by A. W. Ambrose [1, 1921] and L. C. Uren [14, 1927]. The results of water analyses are usually reported from the laboratory in parts by weight per million (volume), i.e. in milligrams per litre, or else in grains per gallon. The following conversion factors are usually employed:

1 grain per U.S. gallon = 17·12 parts per million.

1 grain per Imp. gallon = 14·3 parts per million.

The question of the method of recording water analyses has also been discussed by G. S. Rogers [10, 1917].

An analysis giving weights of radicals often does not bring out clearly the chemical character of the brine, and a consideration of the reaction capacities shows this more clearly.

The reaction capacity of a radical is the quotient obtained by dividing its actual weight by its equivalent combining weight. This quotient is termed also the reactive value of that amount of the radical. For such calculations the reciprocals of the equivalent combining weights can be used, these being called reaction coefficients. If analyses are recorded in terms of chemical compounds, the proportions of radicals present are readily obtained by considering their proportional atomic weights.

The main dissolved constituents of an oilfield brine are the following radicals: the alkalis, sodium (Na) and potassium (K), and the alkaline earth, calcium (Ca), and also magnesium (Mg), all of which are positive radicals, and the acid or negative radicals which divide into the two groups; strong acids, sulphate (SO_4) and chloride (Cl), and the weak acids, carbonate (CO_3), bicarbonate (HCO_3), and sulphide (S). Thus when the weight of a radical is divided by its equivalent combining weight (its atomic weight divided by its valency) or multiplied by the reaction coefficient, the reacting value is obtained which is equivalent in units to milligrams of hydrogen.

To indicate that a radical is expressed as a reactive value Stabler suggested the use of the prefix *r*.

G. S. Rogers quotes an example:

Conversion of Analysis from Ionic Form into Reacting Values (Rogers)

	Parts per million		*Reaction coefficient*		*Reacting values*	*Reacting values %*
Na	435·2	×	0·0434	=	18·88	41·9
Ca	73·1	×	0·0499	=	3·64	8·1
	508·3				22·52	50·0
SO_4	45·9	×	0·0208	=	0·95	2·1
Cl	421·1	×	0·0282	=	11·87	26·4
CO_3	291·2	×	0·0333	=	9·70	21·5
	758·2				22·52	50·0

The reacting value in per cent. thus indicates the character formula of the water and has eliminated the concentration factor entirely.

The character of the water can now be determined by considering these reacting values per cent. The primary bases are sodium and potassium and the secondary bases the alkaline earths and magnesium. The strong acids contribute the property of salinity to a water, and when associated with primary bases they would constitute primary salinity and, with secondary bases, secondary salinity. The weak acids give the property of alkalinity to a brine when considered in conjunction with primary or secondary bases. Thus out of the four properties of a brine, namely:

primary salinity,
secondary salinity (permanent hardness),
primary alkalinity, and
secondary alkalinity (temporary hardness),

only three can be present. Primary salinity and secondary alkalinity will always be present, and if strong acids exceed primary bases in amount, the third property will be secondary salinity, while if strong acids do not exceed primary

bases in amount, primary alkalinity will be the third property.

As the reacting values are being used instead of gravity weights, the proportions can be directly balanced to give numerical values to the above properties.

Continuing the previous example,

	Reacting Value %	
Na	41·9	Primary base
Ca	8·1	Secondary base
SO_4	2·1	Strong acids
Cl	26·4	Strong acids
CO_3	21·5	Weak acid

it will be noted that the strong acids are not in excess of the primary base, so the brine will be characterized by a proportion of primary alkalinity.

Strong acids (2·1 + 26·4)	28·5	Primary salinity = 57·0
Primary base (28·5)	28·5	
Primary base (41·9 − 28·5)	13·4	Primary alkalinity = 26·8
Weak acid (13·4)	13·4	
Weak acid (21·5 − 13·4)	8·1	Secondary alkalinity − 16·2
Secondary base (8·1)	8·1	

Reistle [8, 1927] has pointed out the defects of the Stabler-Palmer system for oilfield work, and states that waters from two separate horizons may in some cases differ only in concentration. Also when the sources of oilfield waters in a given area are closely related, the differences in the waters are small. He considers the use of the Stabler-Palmer system, which groups rather than differentiates waters, to be satisfactory only when waters from two or more horizons differ considerably, and quotes examples of mixed waters the nature of which is more readily distinguished as being different from the two component waters by analyses recorded in the ionic system than in the Stabler-Palmer system.

Analyses of Two Waters and a Mixture thereof expressed in the Stabler-Palmer System and in the Ionic System (Reistle)

	Surface water	*Bottom water*	*Mixed water*
Stabler-Palmer System.			
Reaction values, %			
Calcium	..	8·11	8·01
Sodium	50·00	41·89	41·99
Chloride	43·86	30·25	30·41
Sulphate	6·14	19·49	19·34
Bicarbonate	..	0·26	0·25
Reaction properties, %			
Primary salinity	100·00	83·78	83·98
Secondary salinity	..	15·70	15·52
Primary alkalinity	..	..	..
Secondary alkalinity	..	0·52	0·50
Ionic System.			
(Parts per million).			
Calcium	..	6,240	3,120
Sodium	506	37,000	18,753
Chloride	685	41,000	20,949
Sulphate	130	36,000	18,065
Bicarbonate	..	600	300
Total solids	1,321	120,840	61,187

This is a case of a surface water containing only a small amount of dissolved salts entering an oil-well and mixing to 50% with the bottom water, which is very saline. The analyses reported in the Stabler-Palmer system do not make it obvious that the bottom water has been mixed, whereas the ionic statements, in parts per million, of the three waters show the differences clearly.

If the analyses of the oilfield waters in a formation are known and later in the life of a well a water of analysis different from those in the records is found to be entering, simple algebraic calculation may indicate the water to be a mixture of two separate waters leaking into the well.

The content of the less common constituents of oilfield brines constitutes an interesting subject. Iodine and bromine in oilfield brines have been taken to indicate an oceanic origin. Iodide ion to the extent of 30 to 70 parts per million has been found [9, 1934] in waters from wells at Signal Hill, Long Beach, California. Sulphides, as hydrogen sulphide, occur in many waters, especially in those above the oil. Strontium [15, 1927] and barium have been reported in oilfield waters of the United States. There may be slight contents of ammonium salts in some oilfield waters.

Graphical Methods of Classifying Oilfield Water Analyses

A method has been described by E. G. Tickell [13, 1921] that consists of a symmetrical figure with six axes, formed by joining the vertices of a regular hexagon, as the system of coordinates. Sodium and potassium are recorded on the left-hand upper axis, calcium and magnesium on the right-hand upper axis, carbonate and bicarbonate on the right-hand horizontal axis, sulphate on the fourth (next lower) axis, chloride on the fifth, the sixth (the left-hand horizontal) axis not being used. An objection to this method is that it expresses only the reaction values in percentages.

C. E. Reistle [8, 1927] has developed a method of graphical representation that shows the relationship of the quantities of the various constituents and also their concentration.

The system of J. S. Parker [6, 1929] was also based on the concentration and on the percentage by weight of the constituents in the water analysed, and combines both features. The main graph shows the percentage by weight of the constituents on the vertical scale and the concentration in grammes per litre on the horizontal scale. The graph is plotted on millimetre-squared paper, and the most compact scale has proved to be one-half millimetre to represent 1% on the vertical scale and one-half millimetre to represent one gramme per litre on the horizontal scale. A pictorial method of recording water analyses based on the Parker and Southwell system has been described by E. V. Corps [3, 1933].

The foregoing account will show the value of analyses of oilfield brines in the accumulation of information on subsurface conditions in an oilfield and a guide to the solution of water troubles in individual wells. Due care is needed in the original sampling of the water, and when the analyses are reported from the laboratory, their interpretation is a matter requiring some general knowledge of water problems. The merits and weaknesses of the Stabler-Palmer system of recording the analyses are discussed for the special case of oilfield waters.

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SECTION 13

POWER IN OILFIELD DEVELOPMENT

STEAM DRILLING EQUIPMENT

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STEAM is regarded by many as the ideal power medium for oil-well drilling. No other medium provides the flexibility of operation offered by steam. With steam it is possible to have power both at high speed and low speed. It is easy to reverse the drilling machinery without delay or mechanical difficulties.

Drilling operations are such as to make it difficult to get actual test data. As a result very few facts are knowr about the power requirements of drilling operations. Likewise wide variations of conditions exist in different oilfields and formations.

With the advent of deeper drilling in 1928, one of the large oil companies [4], in conjunction with several of the equipment manufacturers, conducted extensive tests in the Humble field in Texas to determine the advantages of superheated steam. Later the special research committee of the American Society of Mechanical Engineers, under the direction of W. H. Carson, director of the School of Mechanical Engineering of the University of Oklahoma, conducted exhaustive tests on drilling in Oklahoma City [2, 1932]. In the past few months careful tests [1, 1936] on some of the most modern steam-power equipment have been made at Chandler, Oklahoma.

The results of these tests are summarized in Table I. The data are of great importance because they show the improvement in efficiency that has taken place in the period 1928–36. They are also important because they show the requirement of power, fuel, and water for a wide range of drilling conditions. The tests conducted at Oklahoma City were the most exhaustive. They show the difference in fuel and water requirements for both 6⅝-in. and 4½-in. drill pipe in the same formations, using saturated steam with the equipment available at that time.

The tests in the Humble field are particularly interesting because they show the decided advantage of high-degree superheated steam over saturated steam. This test shows a decrease of 11·5% in water required, and 14·3% in fuel required. It was found that with the savings of fuel there was also an increase of 16·3% more work done, resulting in an actual saving of 23·9% in water and 26·3% in fuel.

The test at Chandler, Oklahoma, shows the marked improvement that can be secured when better feed-water heaters, engine-driven power pumps, and improved drilling engines are used, in conjunction with a moderate degree of superheat and insulation of boiler and steam lines.

Complete data are not available on all the tests, so that it is necessary to make estimates by comparison on some of them. At Oklahoma City the daily average requirements and the power-demand requirements were established. Both of these factors are of extreme importance. The daily averages show the amount of fuel and water required, while the power demand shows the size of equipment that is needed to run the rig. It will be clearer, perhaps, what the difference is when it is remembered that no rig runs continuously for 24 hr. per day; consequently the power required when drilling will be higher than the daily average.

The power-demand figures, given on the Oklahoma City test, were determined from the indicated horse-power requirements of the pump and engine when drilling, plus the average daily requirements of the accessories, such as the feed-water pump, turbo-generators, &c. These figures are probably low because the accessory figures are only average. The steam requirements in Table I, used for the pump and engine, are the highest determined during the period of drilling. It is to be borne in mind that there is a depth of hole that has the highest power demand. This is not necessarily the greatest depth of the hole. So far it has not been possible to get sufficient data to determine this point, because the amount of mud circulated, the size of the hole cut, and the speed of the engine enter into this determination.

The Oklahoma City test shows the great difference in power requirements between 6⅝-in. and 4½-in. drill pipe. Due consideration must be given to the speed of drilling in considering this difference.

The data on the Oklahoma City test indicate that the power required for lifting the drill pipe out of the hole down to a depth of 6,300 ft. does not exceed the drilling demand. This is not shown in the data presented in this article.

TABLE I

Compilation of Test Data on Steam-power Plants for Drilling Oil-wells

	Oklahoma City field	*Oklahoma City field*	*Humble field*	*Humble field*	*Chandler field*
Date of test	Sept. 1930	Sept. 1930	Oct. 1929	Oct. 1929	Nov. 1935
Drill-pipe size	6⅝ in.	4½ in.	6 and 4 in.	6 and 4 in.	4 in.
Depth at which data was taken	0–5,570 ft.	5,570 ft. 6,329 ft.	1,800 ft. 4,000 ft.	1,800 ft. 4,000 ft.	0–5,025 ft.
Daily average water used for power, barrels 1 day	1,202	912	497*	440*	359*
Daily average gas used for power, cubic feet 1 day	629,000	425,000	269,124*	230,612*	192,500
B.Th.U. 1 cu. ft.	1,217	1,217	1,400	1,400	1,175
Daily average gas used, 1,000 B.Th.U. 1 cu. ft. equivalent	765,493	529,395	376,936*	322,857*	226,187
Average boiler h.p. per hr.	502	341	246*	238*	152*
Boiler efficiency, %	54·4	52·0	52·8	59·4	55·0*
Boiler horse-power demand 1 hr.	610	443	308	297†	190*
Increase of demand over average horse-power	23·5	30·0	25·0*	25·0*	25·0*
Duration of test, days	30	10	18	18	30

* Estimated. † Doing 16·3% more work than saturated boiler test.

A great deal of stress has been laid on the power requirements for lifting, but it is principally a question of how quickly the driller feels he must get the drill pipe out of the hole. A little more time in lifting the first few stands will reduce the power demand considerably and will scarcely increase the total time of drilling. Hence it is quite possible that in deep drilling the lifting demand need never exceed the drilling demand. Little information is available at present on this point.

In the Humble field tests only the power demand was determined. The Oklahoma City test showed an increase of 23·5% and 30% power demand over the daily averages. Hence a figure of 25% was used to estimate the daily average of fuel and water on the Humble test. At Chandler only the daily average on fuel was taken. Water and horse-power were estimated on a 55% boiler-efficiency basis. The demand figure was estimated at 25% greater than the daily average.

It is of interest to compare the boiler plants used on these tests. At Oklahoma City, four 250-lb. pressure, 125-h.p. small fire-box boilers were used. The radiation load of four boilers has a great influence on the high fuel figures in spite of the moderate power required. It is safe to say that with modern boilers now available, fewer could have been used. Many wells were drilled in Oklahoma City more satisfactorily with three superheater boilers than with four saturated boilers, as were used in this test.

In the Humble test two saturated boilers, 90 h.p., 200-lb. pressure, were used. The two superheater boilers were 65 h.p., 180-lb. pressure, but had a higher percentage of fire-box surface and volume than the saturated boilers. Because of their small size the superheater boilers had to be operated at 228% of rating, while the saturated boilers were operated at only 167% of rating. The superheater boilers operating at a 61% higher rating had an efficiency 6·6% higher than the saturated boilers. This indicates that superheater boilers will produce a greater volume of steam, at an equal efficiency, than a saturated boiler. It also indicates that a superheater boiler of the same size will provide the same amount of power at higher efficiency.

In the Chandler, Oklahoma, test two modern 125-h.p., 250-lb. pressure boilers were used. It was shown, however, that one boiler was capable of running the rig, except when there was excessive jetting of mud. This rig actually used two boilers over most of the drilling periods, so that the fuel figures reflect radiation from two boilers instead of one, which would have been able to supply the power demand. This rig did not have the benefit of all the most modern steam equipment. A separate direct-connected rotary engine was not used. Had only one boiler and the smaller engine with its better water rate and a higher degree of superheat been used, the fuel and water figures would be even better than actually obtained.

A study of the operating data of the tests indicate the great advance that has been made in the efficiency and size of equipment necessary for drilling a 6,000-ft. well. There are certain locations where fuel and water are still plentiful and available at little or no cost. Consequently it is desirable to analyse the various combinations of equipment that can be used for a 6,000-ft. well, and discuss the advantages of each.

Table II gives the comparative costs and weights of four steam-power plants that can be used. It is assumed in these set-ups that a modern feed-water heater is used, and that automatic firing and draught controls are used. Many types of home-made water heaters have been tried with more or less success, but there is now available on the market heaters that are so far superior to the home-made heaters that it is safe to say these will soon be obsolete. Automatic firing and draught controls have so well demonstrated their worth that a rig without them is a rarity.

TABLE II

Comparative Cost and Weights, Steam-power Units for Drilling 6,000-ft Wells

	Cost, $	Weight, lb.
Set-up no. 1		
Unitized direct engine drive rotary with 7¾ × 7 vertical expanding engine	6,981.00	20,175
Mud pump, 7¼ × 18 unitized with 7¼ × 7 vertical expanding engine	9,433.00	36,000
Draw-works expanding engine 12 × 12 single drive	3,800.00	16,200
1 125-h.p. 250-lb. W.S.P. superheater boiler	4,658.00	31,990
Insulation for boiler and line	400.00	4,000
Boiler piping and valves	200.00	1,000
Burners	260.00	1,000
Total	25,732.00	110,365
Set-up no. 2		
Unitized direct engine drive rotary with 7¾ × 7 vertical expanding engine	6,981.00	29,175
Mud pump, 7¼ × 18 unitized with 7¾ × 7 vertical expanding engine	9,433.00	36,000
Draw-works expanding engine 12 × 12 single drive	3,800.00	16,200
Portable superheater	3,447.00	12,000
1 125-h.p. 250-lb. W.S.P. saturated boiler	3,491.00	28,150
Insulation for boiler and line	400.00	4,000
Boiler piping and valves	400.00	2,000
Burners	260.00	1,000
Total	28,212.00	119,525
Set-up no. 3		
Rotary table with chain and sprocket	4,089.00	10,635
Rotary and draw-works engine 12 × 12 non-expanding	2,708.00	14,000
Mud pump, 14½ × 7½ × 18	2,520.00	17,170
2 85-h.p. 250-lb. W.S.P. superheater boilers	7,518.00	51,770
Burners	520.00	2,000
Boiler piping and valves	400.00	2,000
Total	17,755.00	97,575
Set-up no. 4		
Rotary table with chain and sprocket	4,089.00	10,635
Rotary and draw-works engine 12 × 12 non-expanding	2,708.00	14,000
Mud pump, 14½ × 7½ × 18	2,520.00	17,170
2 100-h.p. 275-lb. W.S.P. saturated boilers	6,338.00	55,800
Burners	520.00	2,000
Boiler piping and valves	400.00	2,000
Total	16,575.00	101,605

Based on costs at Tulsa, Okla. Feed-water heaters and pumps, spare mud pump, and firing control not included because they are necessary on all rigs.

Set-up no. 1 consists of expanding engine drives on draw-works, rotary, and mud pump, together with an integral superheater boiler fully insulated and with steam lines insulated. This plant will give the lowest fuel and water figures of the four suggestions at the lowest first cost and weight. In addition it will have the best operating characteristics because it provides high degree of superheat giving live power at all times. When fuel and water costs are high, this set-up of equipment will prove most economical.

Set-up no. 2 is similar to no. 1, except that it provides for saturated boilers and a separately fired superheater. The efficiency will be slightly less than no. 1 set-up, because separately fired superheaters do not provide the high degree of superheat at a comparable price or weight. It does, however, have the advantage of modernizing present saturated boiler equipment.

Set-up no. 3 consists of the non-expanding type drilling engine for combination draw-works and rotary drive with the duplex-type slush pump. This equipment has been used extensively because of its reliability and simplicity. Included in this set-up are 85-h.p. integral superheater boilers. With the high degree of superheat available to absorb the uninsulated line losses and reduce the water rate on the steam cylinders, a remarkable reduction in fuel and water can be made. In addition, the capacity of the unit is increased.

As pointed out from the result of the test on the Humble rig, these savings may reach 26%. This set-up provides efficient equipment with low first cost and is desirable where the drilling rig may be used both at points of high- and low-cost fuel and water.

Set-up no. 4 is the simple power unit including non-expanding engines and pumps with saturated boilers. It is to be noted that these boilers are given as 275 lb. pressure, while all the set-ups with superheat are shown as 250 lb. pressure. Experience has demonstrated that the effective pressure in the steam cylinders with superheated steam will be 25 lb. or more greater than with saturated steam. This is due to the lower pressure drop in the steam lines, the higher temperature of the steam cylinders, the small amount of steam required to heat up the walls, the smaller amount of steam required to fill the cylinder, and the lower back pressure on the cylinders.

It would seem that the no. 4 set-up would be most desirable where fuel and water cost are negligible. However, closer examination indicates that the equipment in set-up no. 3 is considerably lighter in weight. This would reduce the moving costs and more than overcome the slightly higher first cost, when considered over several years with 10 wells drilled per year. The boilers, because of their lighter weight, would be easier to handle. Experience has also proved that rigs provided with superheated steam are much more stepped-up and flexible. Hence, if we do not credit the rig with any fuel or water saving, the advantage of superheat would appear to make set-up no. 3 more desirable than no. 4.

A more recent development for shallow drilling that shows great promise of low first cost and economy of operation has been introduced. This set-up consists of a modification of nos. 1 and 2 set-ups. Instead of unitizing the engines with the pump and the rotary, the engines are connected to a drive shaft so that they can be used to drive the pump and rotary separately. The 12 × 12-in. engine is eliminated entirely. When the hoist is being used the rotary and pump are not operating. The two engines are then used in tandem to operate the hoist. Such a combination provides sufficient power for all loads; it is low in first cost and efficient in the use of fuel and water.

While there is not as much information available on deep drilling, it appears that the advantages of superheat and other modern equipment now available will hold true. In deep drilling the advantages should be even greater. Some of the modern equipment listed for 6,000-ft. drilling will be no larger for 8,000 or 12,000 ft. Except for the addition of one or two superheater boilers, or saturated boilers with a separately fired superheater, and larger engines and pumps, the power equipment will remain the same. The same economics of operation will be maintained, and the first cost and weight will be proportionately less.

The size of the steam-power plants discussed may seem too small for competitive drilling of oil-wells to those who have been accustomed to using more boilers and non-expanding pumps and engines. It may be desirable on all the set-ups recommended to install an additional boiler so that one could be shut down for cleaning and repairs. Some drillers claim that it is easier to supply steam to the rig if more boilers are used. The principal reason for this is that little attention has been paid to proper firing of the boilers. Smoke-box doors have not been kept in repair, and stacks are not properly maintained. Under these conditions it is impossible to operate the boilers at sufficient capacity to provide the power required without excessive jetting of the stacks to provide draught. Only recently have efficient feed-water heaters been used, which also reduce the boiler capacity required.

If the horse-power demand in saturated steam is known for any rig, the number of boilers required can be determined from Table III. Manufacturers recommend that sufficient boilers be selected to take care of the normal power demand when operating the boilers at 200% of rating. They are most efficient at this rating. Tests have shown that they can be operated above 300% if properly fired, and this reserve provides sufficient power for any emergency or peak-load demand. If boilers with integral superheaters are used, the horse-power demand should be reduced 25% before selecting the number of boilers. If the boilers are covered with insulation, the horse-power demand can be reduced a further 7½ to 10% before selecting the number of boilers.

A recent survey of active fields in Texas drilling to depths of 8,000 ft. indicate that there are as many rigs operating

TABLE III

Horse-power Capacity at various Ratings 125 h.p., 300-lb. W.S.P. Boiler

	One boiler		*Two boilers*		*Three boilers*		*Four boilers*		*Five boilers*	
% rating	*h.p.*	*lb. per hr.*	*h.p.*	*lb. per hr.*	*h.p.*	*lb. per hr.*	*h.p.*	*lb. per hr.*	*h.p.*	*lb. per hr.*
100	125	4,312	250	8,625	375	12,937	500	17,250	625	21,562
125	156	5,390	313	10,780	469	15,270	625	21,500	781	26,050
150	188	6,468	375	12,937	563	19,405	750	25,875	938	32,343
175	219	7,546	438	15,092	656	22,638	875	30,184	1,094	37,730
200	250	8,625	500	17,250	750	25,875	1,000	34,500	1,250	43,124
225	281	9,702	563	19,406	844	29,108	1,125	38,812	1,406	48,515
250	313	10,780	625	21,562	938	32,342	1,250	43,125	1,563	53,906
275	344	11,859	688	23,718	1,031	35,577	1,375	47,436	1,719	59,295
300	375	12,937	750	25,875	1,125	38,811	1,500	51,750	1,875	64,686

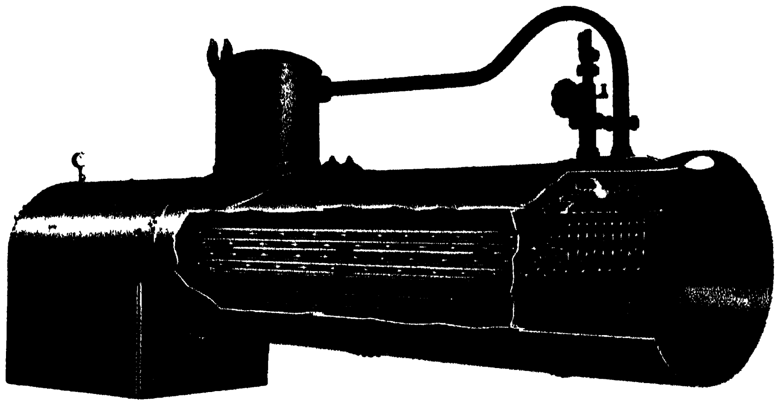

FIG. 3 Oilfield boiler with integral superheater

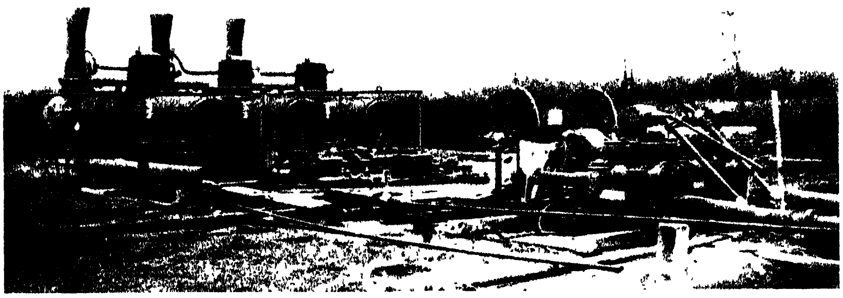

FIG. 10 A modern installation of 15½ × 8½ × 20 duplex steam slush pumps and integral superheater boilers with Venturi stacks

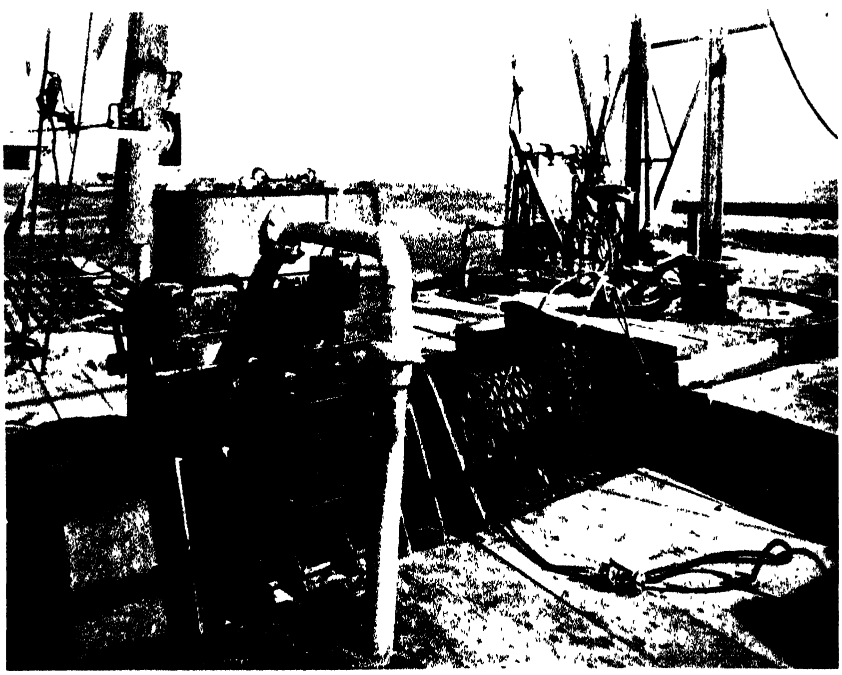

FIG. 11. Rotary direct connected to twin engine through a gear-box

with two 125-h.p. boilers, with $14\frac{1}{2}\times7\frac{1}{2}\times18$ fluid pumps, and with a 12×12 twin engine, as there are rigs with three 125-h.p. boilers, $15\frac{1}{2}\times8\frac{1}{2}\times20$ pumps, and a 14×14 twin engine. Where drillers have gone to the larger equipment there has been little or no expense for fuel. In this case the decreased drilling time and lower labour cost compensate for the larger and more expensive equipment. Furthermore, deeper drilling to 12,000 ft. is anticipated in the purchase of this equipment for fields where fuel and water are available without cost. None of these larger engines or pumps are using expansion, so that the steam demand is much higher than with the power pumps and expanding engines; consequently more boilers are needed.

In studying the test data and the suggested power plants outlined, it becomes apparent that superheat plays a very important part in reducing the fuel and water used, and in decreasing the size of boiler plants.

The theory of economy of superheat is not complicated. It can be best understood by saying that superheated steam provides a larger volume of steam with less fuel than saturated steam does. Thus it is a more efficient power medium.

Table IV gives a comparison of the weight of steam and the heat that must be provided to fill a 15-in. diameter by 20-in. cylinder. It is apparent, from this table, that the quantity of water and fuel is reduced as the superheat increases. When the same amount of heat is lost by radiation or expansion, saturated steam will decrease in volume more than superheated steam.

TABLE IV

Weight and B.Th.U. required to fill a 15-in. Diameter × 20-in. Steam Cylinder with 310 lb. absolute Pressure Steam

	Lb.	% of saturated	B.Th.U.	% of saturated
Saturated steam	1·354	100·0	1,630	100·0
100° superheat	1 155	85·2	1,462	89·8
200° superheat	1·023	75·4	1,358	83·3
260° superheat	0 874	64·3	1,233	75·7

The life of integral superheaters and their simplicity of operation have now been definitely established, so that no one need hesitate to take advantage of the better performance they render. A great number of integral superheaters, as shown in Fig. 3, have been in use for over 5 years without any mechanical or operating difficulties.

The pump and engine equipment that has been manufactured in recent years will not experience any difficulty due to temperature. The maximum temperature obtainable at 300 lb. pressure with integral superheaters at the present time is 675° F. The modern pumps and engines will readily stand this temperature. However, with average-length insulated lines the temperature drop will be 50 to 75° F. With uninsulated lines the temperature will often be no more than 500° F. at the pumps and engines. This is one of the advantages of high superheat, namely, that it will absorb the line losses and still provide some superheat for reducing the water rate of the engine and pump.

The total temperature and superheat available with standard units is shown in Fig. 1. However, where it is desirable to use less superheat, shorter units can be installed in the boilers to provide any degree of superheat desired, as is shown in Fig. 2. The installation of heating elements is simple, so that the change can be made at any time.

Separately fired superheaters are also available and have found a place in oil-well drilling. Where modern saturated boilers are available, the addition of a separately fired superheater to such a boiler plant will greatly improve its economy and increase the capacity. In locations where long steam lines are necessary, and sufficient superheat cannot be provided at the boiler plant to overcome all line condensation and provide superheat for the rig, a separately fired unit can be installed at the rig to great advantage.

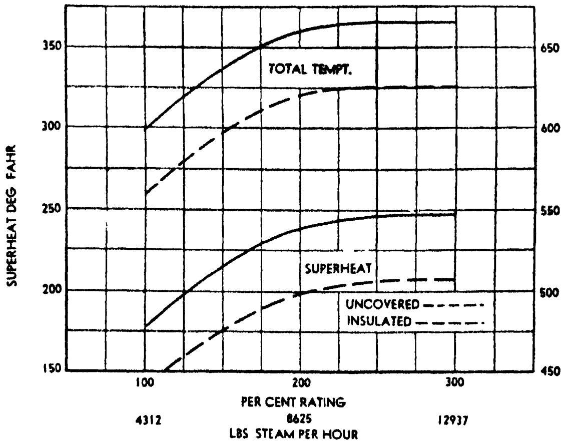

FIG. 1. Superheat and total temperature of 125-h.p., 300-lb. W.S.P. boiler.

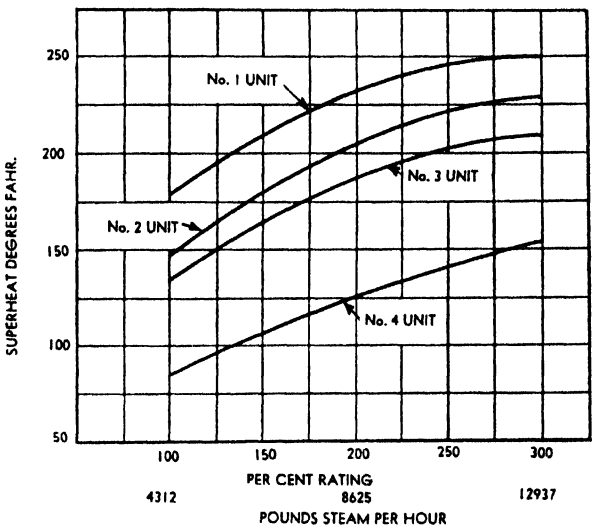

FIG. 2. Superheat for various-length units of 125-h.p., 300-lb. W.S.P. boiler.

The separately fired superheater makes it possible to control the temperature to any predetermined degree. However, controlling the degree of superheat closely is important only if materials used in pumps and engines must be kept within certain working temperatures. The integral superheated variation of temperature will not exceed 75° F. over the working range of the boiler. The heating elements can be selected to give any desired superheat at the 200% operating rating on the boiler, and, as shown in Figs. 1 and 2, this temperature will only be exceeded 10 or 15° F. at the highest rating of the boiler. At ratings below the normal demand some efficiency will be sacrificed. The capacity of the boiler plant, however, is not reduced by this variation at low ratings.

Integral superheaters are well protected from over-

heating. Separately fired superheaters require automatic controls for protection when there is no steam flow, because all the heat of the fire is used for superheating. In the integral superheater, over 50% of the heat of the fire must first generate steam before passing over the superheater. If there is no steam flow, the boiler pressure will rise and open the safety valve on the superheater outlet and provide a flow of steam for protection. Even though the automatic control shuts off the fire on a separately fired superheater when there is no steam flow, sufficient heat is often left in the furnace walls to raise the temperature of the heating surface excessively. This shortens the life of the surface.

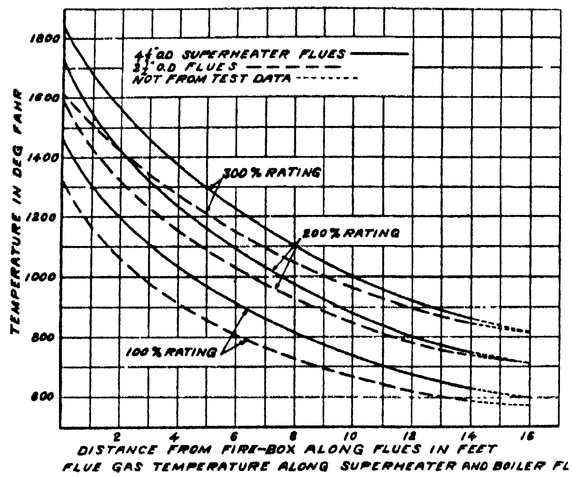

FIG. 4. Flue-gas temperatures along superheater and boiler flues of a 125-h.p., 300-lb. W.S.P. superheater boiler.

The weight, per unit of capacity, of separately fired superheaters has been excessive, but a separately fired superheater that overcomes these disadvantages of weight and short life of heating surface has been introduced. With these improvements the separately fired superheater will give excellent results for a moderate degree of superheat.

When large steam demands became necessary for faster and deeper drilling, the boiler manufacturers were faced with the problem of increasing the capacity of the boiler. It was essential to accomplish this without increasing the weight of the already too heavy boilers, and superheat was introduced.

After considerable study of design, and with the information then available, a superheater boiler was built as shown in Fig. 3 and extensive tests run. A great number of tests, holding the capacity of the boiler for 4-hour periods, at ratings of 50 to 300% were made. Accurate records of fuel, water, and temperature throughout the boiler were kept. Draught readings in the fire-box and stack were made. The composition and the heating value of the fuel were determined. The flue-gas analysis was also carefully noted.

The boiler tested was a 125-h.p., 300-lb. superheater boiler. In addition to the regular data taken in a standard boiler test, a thermocouple was installed in the 4½-in. superheater flues and in the 2¼-in. boiler flues. Temperatures were taken at 1-ft. intervals along the flues, starting at the fire-box tube sheet, as shown in Fig. 4. Similar data have been collected on boilers used in railroad service, but this test represents the only data ever assembled to determine the value of oilfield boilers. Interpretation of this test shown in Table V, on p. 663, discloses some very remarkable facts.

Boilers have always been rated by the A.S.M.E. and A.P.I. codes on 10 sq. ft. of heating surface, irrespective of the arrangement of the heating surface in the boiler. Table V shows that the steam-generating capacity of oilfield boilers is far in excess of 10 sq. ft. per horse-power. Heating surface varies from 0·8 of a sq. ft. per horsepower to 170 sq. ft., depending upon its location.

The total heat required to generate the steam, and the heat required for superheating, was determined from the quantity of water evaporated. The heat in the flue gas leaving the boiler was known. From this it was possible to determine the radiation and unaccounted-for losses. The flue-gas analysis shows only a small amount of incomplete combustion at 200 and 300% of rating. This heat and the hydrogen loss were deducted from the total heat available. The unaccounted-for losses are thus reduced to radiation. The radiation from the boiler is in direct proportion to the outside surface. The radiation was distributed over the length of the boiler in this proportion. The fire-box accounts for 50·2% of the total radiation, and each foot of flue for 3·59% of the radiation.

Since the superheater is installed only in the flues, the heat required for superheating is distributed in proportion to the heat available per foot of flue. This may not be entirely correct, because of the lower temperature difference between the steam and the flue gas. It is not felt, however, that it will affect the results very greatly, for it can be seen, from the tables, that only a small percentage of the total heat required for superheating is allotted to the last 5 ft. of flues away from the fire-box.

The results for 200% of rating will be discussed, for this is close to the point of highest efficiency on the boiler.

Column 2 of Table V shows the amount of steam generated in each part of the boiler. Column 3 is the percentage of total steam generated in each portion of the boiler, and column 4 shows the square feet of heating surface, per horse-power, of steam generated in each portion of the boiler.

It can be seen from the figures that the fire-box generates 84% of the steam, and, as shown in column 8, this is accomplished with 11·7% of the total heating surface. Half-way down the flues, or at the end of the seventh foot of flues, 96·4% of the total steam has been generated with 55·9% of the heating surface. For the last 7 ft. of flues the steam-generating capacity drops off so rapidly that by the time the outlet of the flues is reached there is little more heat available than to take care of the radiation from that portion of the boiler. The fourteenth foot of flue generates only 14·2 lb. of steam over and above its radiation.

This boiler, according to the A.S.M.E. rating, would only be classed as a 110·8-h.p. boiler. By extending the flues 2 more feet, and adding 7% more weight, it would be rated 124·8 h.p. It would not generate any more steam, but would radiate the equivalent of approximately 2 h.p. per hour in these 2 ft.

Since the boiler tested was a superheater boiler, it is interesting to compare it with results that might be expected from a saturated boiler. A saturated boiler, with 98 flues, 3 in. diameter, and the same size fire-box, would have practically the same amount of heating surface per foot of length as this superheater boiler. It is to be noted that the superheater absorbs more than 50% of the heat available in the flues. Consequently, with the same amount of fuel fired, or at the same efficiency, the flues would have to absorb over twice the amount of heat they do at present. The fire-box will not absorb more unless the fuel is increased. This is better understood by examining the data

TABLE V

Relation of Steam Generation to Heating Surface and Weight 200% Rating 125-h.p., 300-lb. Pressure Superheater Boiler

Col. 1	2	3	4	5	6	7	8	9	10	11
	With superheater			*Without superheater*						
Distribution of heat	*Lb. of steam*	*% of total*	*Sq. ft. H.S. per h.p.*	*Lb. of steam*	*% of total*	*Sq. ft. H.S. per h.p.*	*Sq. ft. of heating surface*	*% of total*	*Weight in lb.*	*% of total weight*
Absorbed by water	5,230·0	84·1	0 86	5,230·0	72 5	0·86	129·7	11·7	16,691	52·6
B.Th.U. absorbed by superheater	230·0	..	..	464·0	..	..	..	..	..	..
B.Th.U. absorbed by water	5,460·0	88·0	10·5	5,694·0	79·0	5 2	199·6	18·0	17,766	56·0
B.Th.U. absorbed by 2nd ft. of flues	178·6 5,638·6	.. 90·7	.. 13·5	362·0 6,056·0	.. 84 2	.. 6·7	.. 269 5	.. 24·4	.. 18,841	.. 59·4
3rd ft. of flues	76·7 5,715·3	.. 92·0	.. 31·0	155·1 6,211·1	.. 86 3	.. 15·6	.. 339·4	.. 30·6	.. 19,916	.. 62·8
4th ft. of flues	74·0 5,789·3	.. 93·1	.. 32·6	146·2 6,357·3	.. 88·3	.. 16 5	.. 409·3	.. 37·1	.. 20,991	.. 66·2
5th ft. of flues	69·2 5,858·5	.. 94·3	.. 34·9	140 0 6,497·3	.. 90·0	.. 17·3	.. 479 2	.. 43·3	.. 22,066	.. 69·6
6th ft. of flues	66 9 5,925·4	.. 95·4	.. 36 1	135·0 6,632·3	.. 92·0	.. 17 9	.. 549 1	.. 49·6	.. 23,141	.. 73·0
7th ft. of flues	58·0 5,983·4	.. 96 4	.. 41·7	117·5 6,749 8	.. 93·7	.. 20·5	.. 619·0	.. 55 9	.. 24,216	.. 76 5
8th ft. of flues	47·2 6,030·6	.. 97·0	.. 51·2	96·0 6,845·8	.. 94·8	.. 25·1	.. 688·9	.. 62·2	.. 25,291	.. 79·7
9th ft. of flues	45·2 6,075·8	.. 97·8	.. 53 4	91·7 6,937·5	.. 96·2	.. 26 3	.. 758·8	.. 68 5	.. 26,366	.. 83·1
10th ft. of flues	43·1 6,118·9	.. 98·5	.. 56·0	87·4 7,024·9	.. 97·5	.. 27·6	.. 828·7	.. 74·7	.. 27,441	.. 86·6
11th ft. of flues	29·9 6,148·8	.. 98·9	.. 80·7	60·5 7,085·4	.. 98·4	.. 39·9	.. 898·6	.. 81 2	.. 28,516	.. 89·9
12th ft. of flues	26·1 6,174·9	.. 99 4	.. 92·5	52·8 7,138·2	.. 99·1	.. 45·7	.. 968·5	.. 87·4	.. 29,591	.. 93·2
13th ft. of flues	17·2 6,192·1	.. 99 7	.. 140·5	34·7 7,172 9	.. 99 6	.. 69·5	.. 1,038·4	.. 94 0	.. 30,666	.. 96·7
14th ft. of flues	14 2 6,206 3	.. 100 0	.. 170 1	28·6 7,201 5	.. 100·0	.. 84·4	.. 1,108 0	.. 100·0	.. 31,741	.. 100·0
Totals for 14-ft. flue boiler	6,206·3	100 0	..	7,201 5	100·0	..	1,108·0	100 0	31,741	100·0
B.Th.U. absorbed by 15th ft. of a 16-ft. flue boiler	.. ..	.. ..	.. ..	19·2 7,220 7	.. 100 2	.. .	.. 1,177·9	.. ..	.. 32,816	.. 103·5
B.Th.U. absorbed by 16th ft. of a 16-ft. flue boiler	.. ..	.. ..	.. .	1 9 7,222·6	.. 100 2	. ..	.. 1,247·8	.. ..	.. 33,891	.. 107·0
Totals for 16-ft. flue boiler	..	..	..	7,222·6	100·2	..	1,247·8	..	33,891	107·0

in columns 5, 6, and 7 in Table V. To operate at the same efficiency, the boiler would have to generate 1,000 lb. more steam in the flues with the same amount of heating surface. This does not seem possible, so that it can be safely said that saturated boilers of the same design and total heating surface are not as efficient as superheater boilers.

The data show also why superheater boilers will give a greater overall efficiency of the complete steam-power plant. In Table IV it is shown that less superheated steam is required to perform the same work in the steam cylinder. Granting that the saturated boiler will generate 1,000 lb. more steam at the same efficiency, its total volume will be 16% less. The specific volume per pound of saturated steam at 315 lb. absolute pressure is 1·4695, and for superheated steam, at 315 lb. absolute pressure and 600° F., it is 1·9014. With more volume produced at the same efficiency, and less volume required in its use, the result will be a higher overall efficiency of the drilling rig with superheated steam.

In tests made at Oklahoma City [4], with boilers operating on comparable rigs, it was found that flue-gas temperatures of saturated boilers were higher than superheater boilers. This is easily understood from the data shown in Table V. In generating the same amount of energy the flues of the saturated boiler have to do over twice the amount of work. This higher flue-gas temperature has often been used as the basis of exploiting longer flues in boilers.

Tests were also made with the boiler insulated. Fig. 7 shows the increase in efficiency for insulation.

Very careful radiation data were taken, and these data are reported in Figs. 5 and 6. The radiation curves are for still air. The boiler tests were over 4-hour periods with some wind always blowing. It is to be noted that the radiation can easily exceed these figures two or three times on

windy or rainy days. This indicates the importance of covered boilers from a heat-saving and increased-capacity standpoint. If there was little heat loss, covering would probably justify itself by maintaining the shell temperature constant. The constant change in temperature and pressure on boilers has a great deal to do with leaks. It is apparent that radiation on the boiler does reduce the quantity of fuel required, but not the quantity of water.

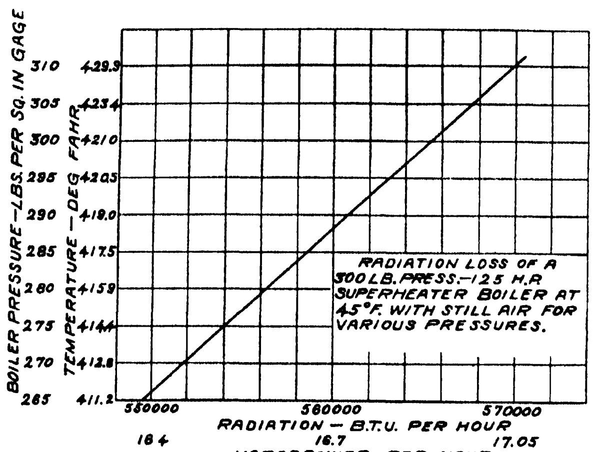

FIG. 5. Radiation losses of a 125-h.p., 300-lb. W.S.P. superheater boiler at various pressures for 45° F. still air.

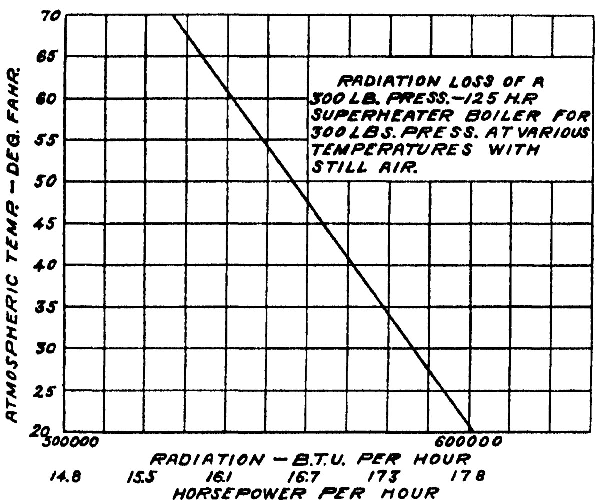

FIG. 6. Radiation losses of a 125-h.p., 300-lb. W.S.P. superheater boiler at various temperatures with still air.

Insulation that is removable when boilers are moved has proved very satisfactory. Fig. 7 shows the efficiency of covered and uncovered boilers.

The data compiled from the test show that the efficiency is highest close to 200% of rating, and does not drop off appreciably at higher ratings. To secure high ratings on oilfield boilers with natural draught would require stacks that are impractical to handle in the field. Consequently there has developed the practice of installing jets in the stacks to increase draught. A survey made of jets indicated that anything from a ½-in. diameter jet to a 1-in. pipe-size jet was being used. Tests were conducted to determine the efficiency of these jets. It was found that a ½-in. jet consumed as much as 25% of the steam generated by the boiler. Experiments were then conducted to design an economical jet to produce sufficient draught to operate the boiler. It was found on test that natural draught provided sufficient draught for tests run at 150% of boiler

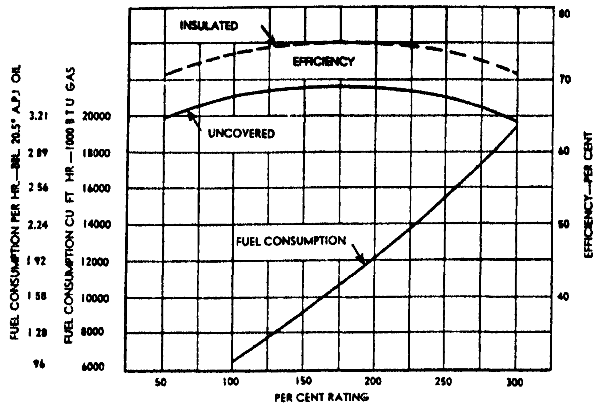

FIG. 7. Fuel consumption and efficiency of a 125-h.p., 300-lb. W.S.P. superheater boiler.

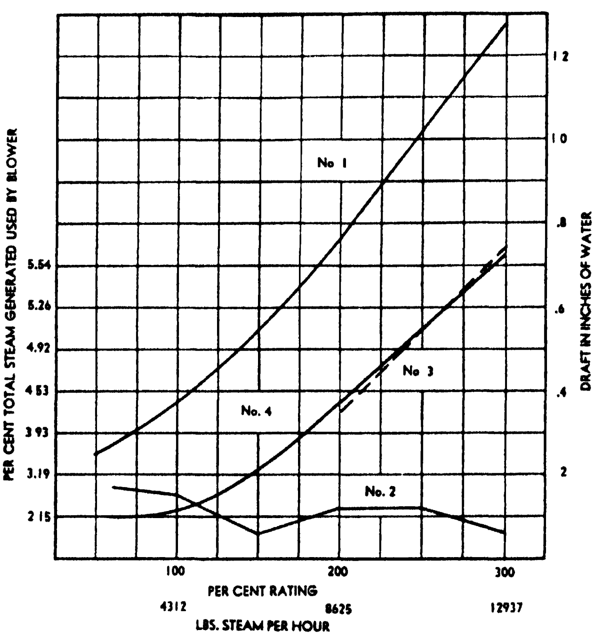

FIG. 8. Draught test on 125-h.p., 300-lb. W.S.P. superheater boiler.
Curve no. 1. Draught required at base of stack.
Curve no. 2. Draught in fire-box.
Curve no. 3. Steam consumption for ½-in. jet in 34-ft.-long regular stack. Natural draught through 150% rating.
Curve no. 4. Steam consumption of Venturi stack.

rating. At 200% there was not sufficient draught with the burners being used. Hence it can be said that the boiler tested can be operated at approximately 175% of its rating with natural draught, if the pressure drop across the burners is no greater than 0·08 of an inch of water, and not over 25% excess air is used. To secure the draught required for ratings above 175%, tests were conducted. It was found that a ½-in. pipe-size jet in the standard 30-in. diameter by 34-ft.-long stack was sufficient. These data, together with the draught required in the fire-box and at the base of the stack, are shown in Fig. 8. It is to be noted that steam consumption does not exceed 5·7% of the steam generated at 300% of rating.

The standard long stacks are very cumbersome to handle. They require guy wires to keep the wind from blowing them over. They are easily damaged and cannot be kept tight readily. To overcome these disadvantages, tests were conducted on short stacks, and the Venturi stack was developed. These stacks weigh 310 lb., compared to 1,360 lb. for the standard stack. They can be erected without a gin pole. They are all-welded, and are complete with bonnet, so that leaks between the bonnet and stack are eliminated. Curve 4 on Fig. 8 is the steam consumption of the Venturi stack used to produce the draught required by the boiler. A study of this curve indicates that the same draught is provided above 175% of rating with steam consumptions no greater than with the long stack with a jet. Below 175% rating the steam consumption is small. Boilers are only operated at these low rates when the rig is not running at full capacity. Hence the capacity of the boiler is not reduced.

Recently there have been indications that the drilling industry would demand boilers with larger fire-boxes and a greater steam space. So long as the boilers must be built with 10 sq. ft. of heating surface per rated horse-power, there will be little advantage in this. Larger steam space is a very desirable feature, but increasing the steam space cuts down the number of tubes that can be installed in the boiler. The tests show that the present fire-box can handle more fuel, and produce more flue gas, than can be got through the flues with natural draught. This makes it clear why the area of flues in a superheater boiler does not have to be as great as in a saturated boiler. It has been shown that the efficiency of a saturated boiler is not as high as a superheater boiler. Lower efficiency means more flue gas at a higher temperature, requiring more area to handle this increased volume through the flues.

The tests indicate the high capacity at excellent efficiency obtainable in the modern oilfield boiler. They prove conclusively the superiority of the superheater boiler for oilfield service. No other type of boiler offers such high capacity at comparable weights, or at such efficiency. Other types of boilers have been suggested such as water-tube boilers and marine boilers. The former requires a heavy refractory setting and a steel casing. The latter cannot provide sufficient fire-box volume or flue area. It also requires a larger diameter with correspondingly heavier plates in its shell.

In many locations where fuel and water are easy to obtain the direct-acting duplex steam pump is used. The low cost of this type of pump has had a great influence in its increasing use. The water rate of this type of pump is necessarily high because no expansion of the steam takes place in the cylinder and radiation is excessive because of the slow speed. Superheating has reduced the water rate of this type of pump, as shown in Fig. 9. An installation of large duplex steam pumps operating on superheated steam is shown in Fig. 10.

Because of the high water rate of the duplex steam slush pump a great many power-driven slush pumps are now being used. Both turbine and steam-engine drives have been used. A recent paper [3, 1936] points out the advantages of the engine drive over the turbine drive.

Proper engine size for power-driven slush pumps is important. If the engine is too small, it will not have sufficient horse-power capacity at slow speed when small liners are used in the pump to develop high pressure for deep drilling. Hence it is desirable to have sufficiently large cylinders and a variable cut-off so that a minimum amount of steam can be used at any pump speed found desirable. One manufacturer has recently introduced a 9×8 twin engine to be used to drive a rotary table or a 250 hydraulic h.p. pump. They are also developing a 10×10 twin engine to drive a 350 hydraulic h.p. power pump.

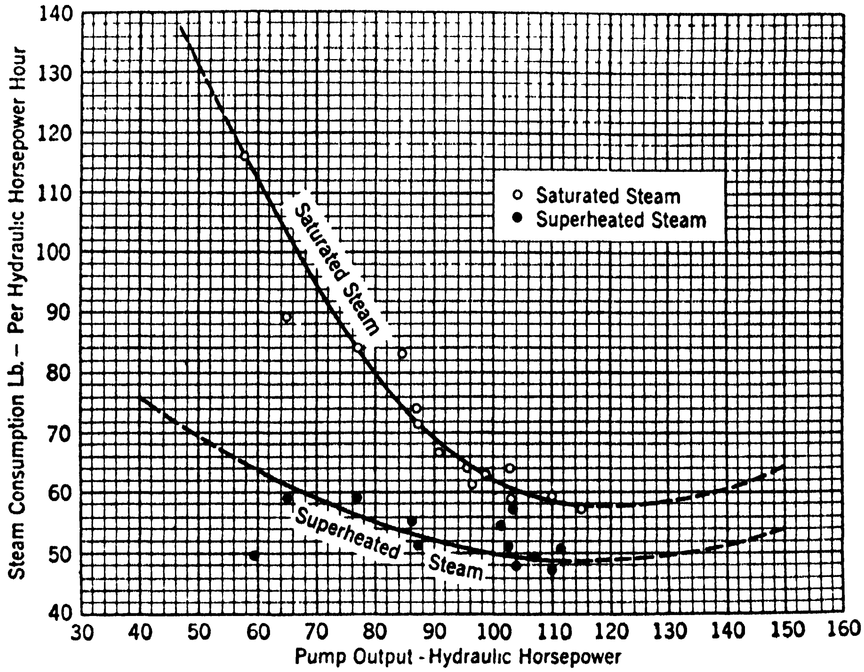

FIG. 9. Steam consumption of a 12×6×16 duplex steam slush pump.

Until recently it has been universal practice to use one engine to drive the rotary table and hoist. The hook-up of chain drive to hoist and from hoist to rotary has proved a very simple method. As drilling has increased in depth, the engines have become extremely large because of the great weight of large-size drill stem. To lift the drill stem it was either necessary to increase the steam pressures used or increase the cross-section of the engines. As a result there are now many large 14×14-in. twin-cylinder engines being used on the rigs for deep drilling. Where fuel and water are not serious factors this scheme is satisfactory even though the capacity of the large engine is only used during the hoisting period.

The power required to drive the rotary is only a small portion of that used in hoisting. The engine is therefore operating at a very uneconomical load factor when driving the rotary table. Most of the large twin engines used up to the present time were not equipped with variable cut-off to get the economy of the expansive force of the steam. To overcome this lack of economy it is becoming quite common to use a small separate engine for driving the rotary. Several of these engines are now on the market

equipped with cut-offs to utilize the expansive force of the steam. It is estimated that 20% saving in steam is made, since a choice of engine speeds and cut-offs can be used.

Fig. 11 illustrates a vertical twin-cylinder engine direct-connected to the rotary through a suitable gear box. Since this is a recent development there will probably be many methods tried to provide the most useful arrangement and to keep the derrick floor space free of obstructions. One hook-up is now being installed that will utilize the small engine as the stand-by drive for the draw-works so that it can be used in case of failure of the hoisting engine.

Because of the larger first cost when two engines are used, efforts are being made to utilize one engine for driving the slush pump, hoist, and the rotary. In this system the engine connected to the hoist and rotary has an extended shaft so that a drive can be made to the slush pump through a clutch. The power load on the engine during the drilling period to run the rotary and slush pump is probably no greater than when hoisting the drill stem from deep wells. The single-engine system is, however, lacking in flexibility. For this reason the use of two small engines connected to a common drive shaft so that they can be used individually to drive the rotary and the slush pump and in tandem for operating the hoist looks more promising. As development takes place there is no doubt that more economical engine drives will be used.

It has been pointed out in the discussion of the various set-ups for drilling that feed-water heaters are essential. Feed-water heating has been followed for some time in drilling practice, but without much regard for the efficiency of the heaters. The usual type of heater used has been a closed coil placed in a large pipe or shell to which is supplied exhaust steam for heating indirectly. This is commonly called a closed-type high-pressure heater. To provide an efficient closed-type heater of sufficient capacity for a modern rig would not be economical. Furthermore, it cannot be kept clean and loses its efficiency very rapidly. The scale from the water deposits on the inside of the coil and makes it expensive to clean. Observation in the field of closed-type heaters indicates that they seldom heat the water over 125° F. after being in service on more than a few wells.

Recently open-type low-pressure heaters have been used successfully in steam drilling rigs. Fig. 12 shows a modern open-type feed-water heater integral with feed-water pump. It is of the jet-condenser type in which the water to be heated is sprayed into a chamber containing exhaust steam from the pumps and engine. The heater is usually operated at an exhaust steam pressure of about 10 lb. per sq. in. gauge. The feed water can thus be raised to 210° F. This results in a saving of 10 to 12% in the amount of heat required to generate steam pressure 300 lb. per sq. in. over that required when using feed water at atmospheric temperature.

There are also operating advantages of the open-type feed-water heaters now being used. All the exhaust steam condensed is returned to the boiler as pure water so that scale formation is reduced approximately 15%. This results in cleaner boilers as shown in a recent paper [3, 1936].

The open-type heaters have been a big step forward in recovering exhaust steam and in returning pure water to the boiler. The development of satisfactory condensers except in special cases has been slow because of the difficulty of building portable condensers of sufficient capacity. Progress is being made and several simple designs are under consideration.

In the Gulf Coast area on barge drilling, simple closed-type condensers have been in service with excellent results. In this case it is only necessary to pump sea-water over the condenser, which flows right back into the bay.

One of the greatest problems of the steam drilling rig is hard water encountered in many locations. Until recently little attention has been paid to preventing scale formation in the boilers. By the use of proper treating methods most of the scale encountered can be kept soft and blown down from the boilers. This is being done successfully in the New Mexico area.

There has recently been introduced in a South Texas field a portable water-heating and treating plant to purify the water before entering the boilers. The advantages of water treating are so great that more attention will be given to this problem in the near future.

Proper lubrication of steam pumps and engines has been difficult. Automatic lubricators that will stand the vibration of portable equipment have now been developed. Much of the difficulty in the past has been due to the operators not keeping the lubricators full. The slow-speed engines and slush pumps operating on wet steam ran fairly successfully even if lubricators were neglected occasionally. With the advent of higher speed expanding engines and turbines operating on superheated steam some difficulty has been encountered with excess wear on the cylinder and valve parts due to this neglect. Lubrication can be carried out better with dry steam than with wet steam, provided the proper type of lubricators are used. Fig. 13 shows a durable forced-feed lubricator now being used extensively in oilfield service.

In addition to improvements to the major equipment a great deal of attention has been paid to the details of the entire steam-power plant. Unnecessary fittings and turns in steam lines which reduce effective pressure are being eliminated. The lines are being put up out of water holes and are being insulated to conserve heat. There has been a remarkable simplification of boiler hook-ups to reduce the cost and increase the efficiency. Several boiler manufacturers have moved the steam outlet nozzle of the boilers to the side of the dome to simplify the steam manifold connexions.

Greater attention is being paid to maintaining tight smoke boxes and stacks on the boiler. Automatic control of the firing and steam required to operate the stack jets have been introduced successfully. Low water alarms to prevent danger of explosions are now extensively used.

Hence it can be seen that the economic changes in the oil-production industry has brought into the steam drilling rig much of the modern equipment and methods used in the more efficient industrial steam-power plants. By more closely following this development in steam efficiency the oil-producing industry will retain its ideal steam power.

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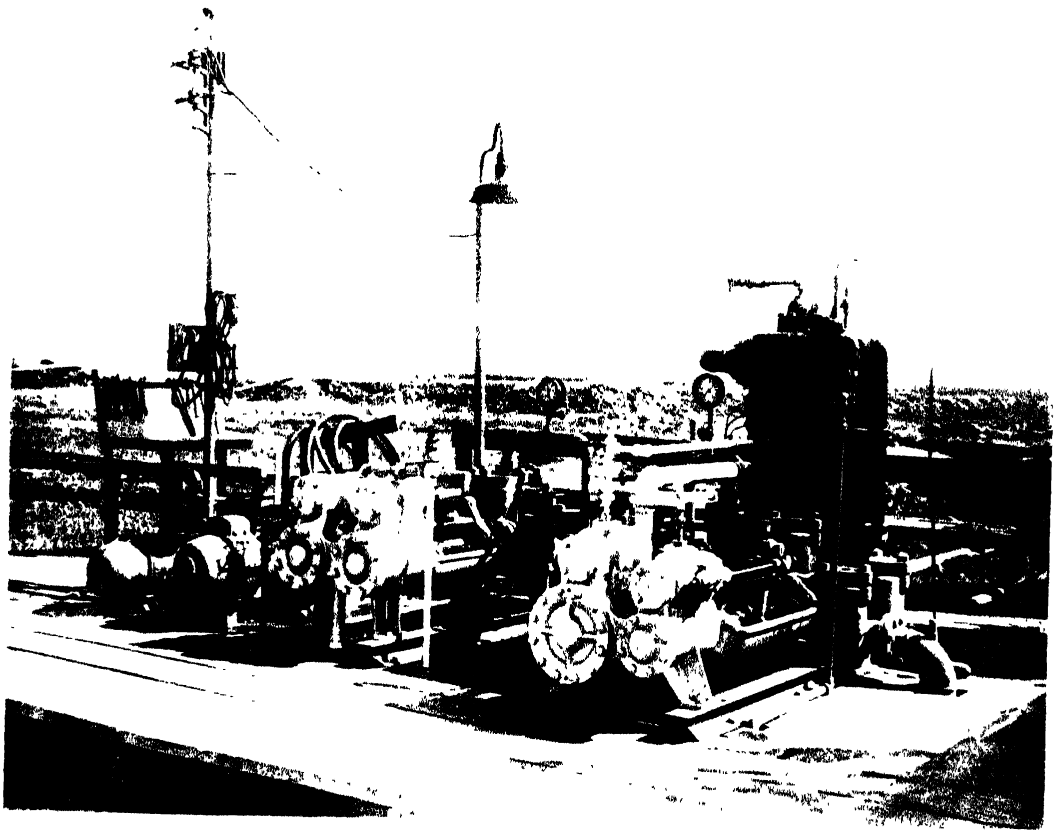

FIG. 12. A combined feed pump and heater with spare boiler feed pump and turbo generators. More recently all these units are assembled on one set of skids for ease of handling in the field

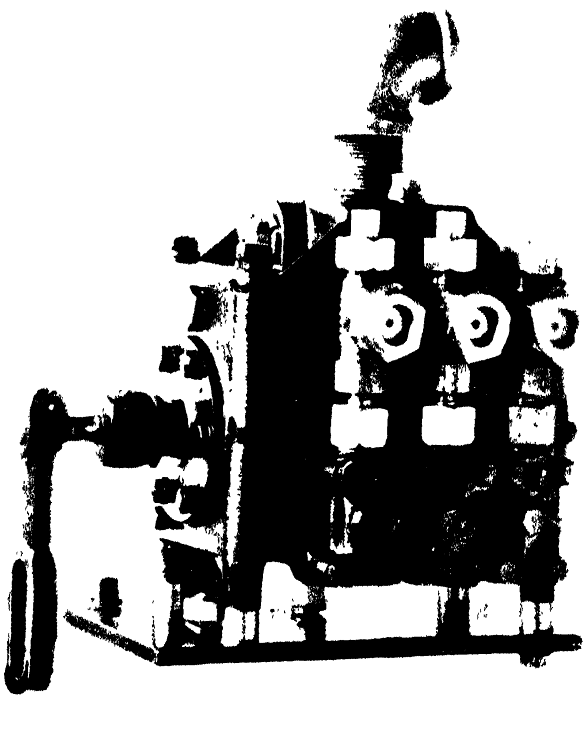

FIG. 13. Forced feed lubricator for steam drilling equipment

INTERNAL-COMBUSTION ENGINES FOR OILFIELD DRILLING PRACTICE

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STEAM still remains the most popular source of power for drilling oil-wells, due to the fact that it possesses certain inherent advantages for this service. It possesses the ability to start heavy loads from a dead stop or a high overload capacity and high starting torque. The dependability and flexibility of steam are well recognized, and although the steam-driven rig is a relatively inefficient piece of machinery the additional flexibility obtained enables this type of power to maintain its popularity.

The modern Diesel or compression ignition engine has established itself in oilfield work for a variety of drives and particularly for oil-well drilling. The fact that Diesel engines can be operated more economically than any other type of prime mover has assisted considerably in popularizing this type of power.

Fuel for Diesel engines is almost always economically procurable, and in isolated areas or in fields where little or no gas is being produced this type of prime mover shows distinct advantages. Water requirements are much lower than with steam-operated prime movers, and in districts where water is scarce and thus expensive to purchase or to produce, or where the water requires treatment before use in the boilers, a considerable saving will be shown.

The sizes of Diesel engines in use will vary with the work to be performed, small powered engines only being necessary for shallow wells, with higher powered engines for the deeper wells and for carrying heavier loads.

Engines now available range in horse-powers and weights from the light-weight engine of 120–50 h.p. to the larger types weighing about 10 tons and developing up to 400 h.p. In general, Diesel engines are readily transportable by trucks, but where the weight of an engine is too great for one truck to carry, the horse-powers may be reduced and the engines operated in tandem or even in multiple units.

The Diesel-operated drilling rig shows a distinct operating economy both in respect of fuel consumed and in the quantity of cooling water required for the radiators. Evaporation is very small and sufficient water should always be available from the drilling supply.

The modern Diesel engine has a wide range of flexibility, and this fact makes for adaptability in drilling operations. An engine which normally operates at a full speed of about 650 r.p.m. can be accelerated from a slow speed to its maximum in a few seconds, and due to its high torque heavy drilling strings and casing strings can be picked up easily at the desired speed. These engines develop an increasing torque as the speed is reduced, and under heavy load their pulling characteristics come into operation.

In many cases the Diesel engines used for drilling power are convertible to operate on natural gas by means of a special combustion chamber, gas-mixing valve, and an electrical ignition system.

The most popular method of driving the draw-works and pumps of a rotary drilling rig involves the use of two engines of the same rated horse-power and speed, of the convertible type. The engines are connected through V-belt, chain, or gear-box to the slush pumps and draw-works in such a way that the power from either engine can be used to drive either of these or can be compounded for hoisting operations.

Due to the wide range of speeds and fluctuations of load encountered in rotary drilling considerable flexibility of control is essential. Such flexibility is obtained from the steam engine without any difficulty, but in order that the Diesel engine should give similar service perfect combustion and equal distribution of load under all conditions are absolutely necessary. Fuel and governing systems have therefore been developed. Depth of hole is another factor to be considered when the selection of the prime mover is to be made. The deeper the hole the heavier the rig, and hence the greater will be the horse-power necessary to handle the heavy strings of drill pipe. In cable-tool drilling light high-speed units are all that are necessary.

Dependability is an essential requirement for rotary drilling, and as a result the well-known two-cycle, solid-injection, slow-speed, horizontal engine has been adapted to this service. Simplicity of design with one or two cylinders and few working parts have enabled these engines to be operated by untrained men, an important fact in view of the lack of experienced and trained Diesel-engine operators. The clutch used with this type of engine is a reversing and friction clutch with heavy-duty twin-disk forward clutch and differential reverse. This clutch may be operated with ease from forward to reverse.

Diesel engines can be used directly coupled to the power parts of the rig or through an auxiliary source of power such as generators and exciters. The connexion in the latter case may be direct to the engines or by belting.

A disadvantage of the full mechanical drive in which the Diesel engine is coupled through clutches, gears, chains, or belts direct to the drilling equipment is that considerable floor space is required in the rig to enable the equipment to be lined up with the draw-works and rotary table. This may present difficulties in certain cases, particularly in those areas where the ground is swampy or where the derrick is erected on piers in the offshore locations such as in the Venezuela fields.

Diesel-electric drives, on the other hand, may be mounted some distance from the derrick and the power fed through cables to the electrical equipment on the derrick floor. This is a distinct advantage in the offshore locations where the Diesel-electric equipment can be carried in a barge in the vicinity of the derrick.

Comparing the two types of drive it will be seen that a much greater overall full-load efficiency is possible with the straight mechanical drive than with the Diesel-electric drive. In the former case the efficiency may be between 90 and 97%, depending upon the type of transmission system used, whilst for the latter the efficiency will be between 82 and 86%. These figures do not, however, indicate superiority of the direct drive over the Diesel-electric drive, as the real characteristics encountered in drilling are varying loads, reversing loads, varying values of torque, and varying speeds, and not constant loads, torque, and speeds.

During the hoisting operations the starting torque will be in the neighbourhood of 200% full-load torque, whilst the normal running torque with the load in motion will be 100% of full-load torque.

In order to obtain the higher torque values with the mechanical drive some mechanical means must be employed to lower the driven speed, and the clutch must be of sufficient capacity to accelerate the load at the increased torque value without stalling the engine.

After the hoisting operation has started the mechanical drive can only show about 50% of the driven speed, the engines thus being only half loaded. As the speed is fixed by the gear arrangements and cannot be varied in proportion to the torque this is a serious disadvantage.

With the direct-current electric drive 200% full-load torque can be exerted at the start, and as the load falls off the motor can be brought up to approximately 85% of full-load speed. In this case the engine would be operating at about full load, and the rate of pulling out would be about twice the rate that could be obtained by the straight mechanical drive.

It is clear, therefore, that although the mechanical drive shows a higher efficiency, the fact that its speed is dependent upon the starting torque and cannot be varied after the cycle has started makes this type of drive less desirable than the Diesel-electric drive in which it is possible to apply the greatest portion of the engine capacity to doing useful work regardless of speed or torque of the driven load.

In general, Diesel engines are used in conjunction with some other type of power such as direct-current generators and exciters through direct coupling or belting, but a direct reversible Diesel engine driving through a clutch and a flexible coupling is now available. This unit has given results which compare favourably with that obtained by other types of prime movers. The engine is directly connected through a sprocket chain to the draw-works without a reverse clutch, since the engine is a direct reversible type which can be started, stopped, reversed, and accelerated as desired.

The unit consists of a 400-h.p., 600-r.p.m., 8-cylinder direct reversible Diesel engine driving the rotary table and draw-works through a twin-disk clutch. Located beyond the clutch is a flexible coupling and an extended shaft supported at both ends on self-alining ball bearings. Attached to this shaft is a standard sprocket for driving the draw-works shaft. Since the engine is direct reversing there is no necessity for jackshafts and clutches between the engine and the draw-works, and the releasing of the jaw clutches is taken care of by reversing the engine itself.

The twin-disk clutch is built into the flywheel of the engine and is operated by an air ram, the compressed air being supplied by an electric motor-driven compressor.

The engine is governor controlled only for overspeeding, and to obtain flexibility in speed a fixed setting of the hand control has been found most satisfactory. This flexibility in speed enables the power plant to cushion some of the action of the bit when drilling through steeply dipping rock formations. If the speed of the engine drops when the bit is caught, the power impulses are increased by means of a specially designed injection system, maintained under a constant pressure. A fluctuation in speed with the operation of the bit is therefore permitted without the possibility of the engine stalling. The application of this device has thus enabled the clutch to be of a sufficient capacity to accelerate the load at the increased torque value without stalling the engine. During hoisting operations flexibility is obtained by hand control. The average fuel consumption of this engine is about one barrel of oil per 24 hr., and the speeds range from 150 to 500 r.p.m.

With this type of prime mover the engine can be speeded up by throttle control in direct proportion to the horse-power required, and this is a distinct advantage over the Diesel generator installations. In the latter type of power plant the engine must be run at full speed all the time, resulting in excessive fuel consumption and consistent wear on all the working parts.

In the delta area of the Orinoco River in the eastern portion of Venezuela the land is accessible to river craft, and any transportation is by this means. As a result the companies operating in this area have developed equipment that is suitable for transportation on the water and to meet the conditions peculiar to such places.

The cost of transporting fuel oil to the steam installations at widely separated locations, and the very poor quality of water available for boiler purposes, influenced the operating companies in their decision to experiment with motorized drilling units.

The rigs used for the locations in the river and waterways are supported on piles to reduce the expense of heavy foundations, and all possible equipment is mounted on barges. More separate groups of material are therefore required: power barge, a barge to carry the slush pumps, and drilling equipment.

The main power barge consists of an electrically welded steel hull carrying fuel and water compartments together with three 250-h.p., 514-r.p.m., 6-cylinder solid injection, full Diesel engines directly connected to generators and exciters. The engines are of the vertical type, equipped for air starting, forced lubrication, and temperature control.

One Diesel engine operates the drilling motor and one the pumps, the third being a stand-by available for replacing either of the other two should a break-down occur.

Internal-combustion engines operating on natural gas or gasoline are generally of the multi-cylinder type rated at from 125 to 300 h.p. with speed variations of from 330 r.p.m. to approximately 1,000 r.p.m. Lack of flexibility and limited power are among the disadvantages of this type of power, but increased flexibility may be obtained by the use of engine-driven generating units.

In the straight mechanical drive used on drilling rigs two or more engines are generally used. One engine is coupled to the draw-works line shaft through a reversing clutch which provides the speed reduction. A belt or rope drive then transmits the power to the draw-works from the reversing-clutch drum. The slush pumps are driven by separate engines, connexion to the engine being made through a train of gearing.

Flexibility is low with this type of plant, but it has the advantages that fuel costs are low and the quantity of water required per foot drilled is small.

For drilling wells in unexplored areas, therefore, this type of plant may be used to distinct advantage.

To obtain increased flexibility the internal-combustion engine may be coupled up to either direct-current generating units or alternating-current generating units. The latter type of unit is probably not so popular as the former on account of the difficulty of proper voltage regulation and the problem of paralleling two or more machines. As a result the majority of units in operation are of the direct-current generating type.

Considerable ingenuity is being shown in the design of plant to obtain increased flexibility, and one of the most

interesting is the quintuplet rig which employs five small engine-driven generating units to provide the necessary power for the operation of the rig. Each of the five engines develops 87 h.p. at 1,200 r.p.m. at 90 b.m.e.p., and can be operated on gas, butane, or natural gasoline. The engines are connected to generators separately, but the single units have been so arranged that they may be used alone or in any other combination with the remaining four units.

Two units are coupled to drive the draw-works and table through a drilling motor which delivers 250 h.p. at 900 r.p.m., the power of the motor being transmitted to the draw-works by means of a single-reduction gear and a chain drive.

Three engines, connected in series, drive the mud pumps, and arrangements are made for one or more motors to be disconnected when the pressure of the pump exceeds that at which it is rated. Thus for 6-in. drill pipe the three engines and generators will deliver the rated pressure, but with 4-in. drill pipe pressures will be too high and one unit is cut out, thereby reducing the revolutions per minute of the motor and hence the pressure.

For hoisting operations the drilling motor is coupled to five generators in series, and the power of the five engines is thus made available.

In this five-engine unit a complete distribution of power is obtained. During drilling horse-powers of less than 50 may be all that is necessary for the rotary table, whilst the pump may demand high power. With the conventional two-engine hookup the operator is limited to one engine on the drilling motor which may be running on light load and the other on the pump which is running on a heavy load, or both engines mechanically tied together so that any excess power of the drilling engine can be distributed to the mud pump.

With the five-engine unit the generators used to drive the pump are operated at 125 volts with three connected in series, and since the motor is rated at 375 volts the total voltage of the three generators exactly equals that required to operate the pump at its rated speed. For the rotary table two generators are connected in series and can be operated at whatever voltage is needed to drive the drilling motor. Power can thus be distributed throughout the rig as desired, and there will be no excess power in any one place.

Generally speaking, internal-combustion engines are favoured mostly for portable drilling rigs for drilling in shallow areas or for testing out new locations.

The general type of rig is capable of drilling to depths in excess of 4,000 ft., but the diameter of the hole drilled is limited by the capacity of the mud pumps that may be considered as portable.

The engines are designed to operate on gasoline or natural gas and develop about 125 h.p. at a maximum speed of 1,800 r.p.m. Two engines are used and are so arranged that they may be operated independently or together as the work demands. One of these engines is the truck engine which hauls the portable unit to the site, and this engine and the auxiliary one share the duties equally.

The portable type of plant for operating pumping rigs in addition to servicing pumping wells has only recently been developed. Previously it was the general practice to operate pumping wells from a central power and to service the wells by means of portable hoisting machines geared to an internal-combustion engine for pulling sucker rods, tubing, and for cleaning out the wells. Engines to carry out this dual purpose require a wide range of speed and power. Both classes of operation must secure equal attention so that there will not be a sacrifice of one class at the expense of the other. Pumping speed and suitable rapid speed and power demanded for hoisting purposes are frequently not completely satisfactory. The requirements of the dual-purpose engine have been met by the use of the two-stroke cycle design of the horizontal type as against the four-stroke cycle type.

For single-purpose duties it is most economical to use the four-stroke cycle principle, but single-cylinder two-stroke cycle engines can be used for both single and dual purposes on account of their greater simplicity in design and a more uniform flow of power at slow speeds.

Internal-combustion engines may be broadly divided into two groups, slow-speed engines running at from 140 to 240 r.p.m. and high-speed engines running at from 400 to 1,500 r.p.m.

The selection of which type of engine to use is determined first of all by deciding whether or not to use a single-speed reduction in the connexion to the driven crank unit of the rig machine or to employ a double or triple reduction. A general adoption of the double-reduction driving connexion has now taken place, and a driven pulley is now placed intermediate between the driven crankshaft and the engine.

The use of more compact, higher speed engines of the multi-cylinder vertical type is made possible by the use of double-reduction pumping machines. The most common type employs the four-stroke cycle principle, although the two-cylinder two-stroke cycle engines are competing strongly with the four-cylinder four-stroke cycle type.

By far the greater percentage of engines in use in oilfields are the single-cylinder horizontal type of either two- or four-stroke cycle principle.

The use of natural gas in internal-combustion engines is facilitated by proper carburation. Loss of power can be reduced and improved economy obtained by regulation of the pressure of the gas on entry to the engine and by the use of a properly designed carburettor.

Scrubbing of the gas prior to reducing the pressure at which it is collected will aid considerably in increasing running efficiency. All foreign matter is removed from the fuel during the scrubbing operation, and a cleaner-running engine results.

Butane has been used successfully to drill a deep well, and although this gas has been used previously this is the first occasion on which it has been applied to deep-well practice.

The fuel used was a mixture of butane and isobutane containing some propane and was a by-product of casing-head gasoline manufacture. A large part of this gas would normally be wasted in the tail gas from the gasoline plant if not used in this way.

The gas was stored under pressure in liquefied form until required at the well. As the pressure was let down to about atmospheric pressure the butane was again converted into a gas and passed to the two 300-h.p. 6-cylinder internal-combustion engines. No special adjustments were required for either air or timing in operating the engines with this fuel.

The application of these Internal Combustion engines to oilfield drilling practice will, no doubt, increase considerably as more experience is gained. Further improvements in the clutch and transmission arrangements will add to the success of the mechanical rig and result in more reliable operation and a reduction in maintenance costs.

GENERAL ELECTRIFICATION OF OILFIELDS

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THE general principles applying to electrification in the Oil Industry have been dealt with fully in the section entitled 'General Electrification of Refineries', and these principles apply equally to the electrification of oilfields. They will not, therefore, be repeated here.

The special problems of oilfields electrification are primarily found at the actual drilling or pumping points, generation, transmission, and distribution being of a type applicable to all kinds of industrial works.

In addition separate gas-, oil-, or steam-engines driving generators may be used for the individual drillings of wells, and supply the electric motors used for drilling, hoisting, and other operations.

The methods adopted in actual drilling are covered by two main classes; the 'percussion', in which the hole is drilled by blows delivered by the lifting and dropping of a bit, and the 'rotary', in which the hole is drilled by the rotation of a drill-pipe and bit.

In the percussion system the bit is oscillated vertically by means of a pivoted beam, which is in turn driven by a crank connected to the band wheel to which the electric motor is coupled by belt drive. For this duty a two-speed slip-ring induction motor with suitable rotor-regulating resistances is generally used. The higher speed is used for hoisting and bailing operations, and the lower speed for drilling.

Where a considerable amount of gas is present in the fields it is necessary to make special arrangements in order to ensure that the equipment is entirely safe from a fire-risk point of view.

As the necessity for more rapid and continuous drilling was appreciated and the depths of wells became greater, the rotary system of drilling came into use. This is the most elaborate form of drilling equipment in general use, and calls for a considerable supply of power. The electric motor drives the draw-works, which in turn drives a rotating table which has in its centre a square hole through which is fitted a length of square tubing screwed to the drill pipe. At the top of the square tubing is connected a length of flexible hose, through which a constant supply of slush or liquid mud is pumped.

In addition to the rotary drilling motor and control gear, each rotary drilling equipment is provided with one or two motor-driven slush pumps.

The size of motor necessary for the actual drilling depends principally upon the depth and method employed. Generally, the rated output of the motor is greater than that required for the actual work. The size of the motor is therefore not determined by the drilling itself, but by the auxiliary work connected with it, which for short periods requires a considerably greater output.

These auxiliary operations include:

(*a*) Raising the rope and bit, &c.; this operation is necessary to change the bit.

(*b*) Raising the casing to line the hole in accordance with the progress of the drilling.

(*c*) Freeing any casing which may have been frozen.

(*d*) Raising sludge with the bailer.

Some of the auxiliary operations enumerated above necessitate very high motor outputs. The operations are always of the nature of winding, that is, the raising and lowering of loads suspended from a rope.

Electric motors employed for all drilling rig drives should be designed for a considerable overload capacity and for a high ratio of speed regulation in either direction of rotation. In some cases special provision would have to be made to avoid the ignition of ambient inflammable gases by sparks produced on the slip rings during operation. Where necessary, the switch-gear starters and regulating apparatus must also comply with these requirements.

The driving motors can be of the three-phase type with slip-ring rotors, the speed regulation of which is effected by throwing in resistances in the motor circuit.

These motors are generally of the end-shield-bearing type, fitted with flameproof explosion-proof enclosed slip rings with brushes permanently set and strong belt pulley. On account of the heavy stresses they are subjected to, the difficult conditions of transport, and the generally unskilled labour in attendance, the motors should be constructed in a specially robust and compact manner, with reinforced shaft and feet, strong bearings, and large air gap. The electrical portion should be liberally dimensioned and have a normal stalling torque of at least three times the full-load torque.

The insulation must be of the highest quality, and the temperature rise under actual operating conditions must be such as to eliminate the possibility of dangerous overheating.

The starting and speed regulation is usually effected by means of controllers, the contacts of which may be air break or oil immersed and enclosed in a flameproof case. The contacts of the controllers should be of substantial construction, in order to meet the mechanical and electrical requirements of the drilling operations.

The starting and regulating resistances can be mounted on a framework with the controllers, or may be placed in a separate frame. The resistances should be of the unbreakable type. Care must be taken in the design of the resistances to ensure that during use a dangerous temperature is not reached. As a safeguard against this, temperature relays may be used—these act on the no-volt release of the main circuit breaker and cut off the motor from the supply when a predetermined resistance temperature has been reached.

The switch gear used for the isolation and protection of the motors should be of the air-break or oil-immersed type, fitted inside a flameproof and explosion-proof case.

The size of motor most usual in percussion drilling is 75 h.p. at 720 r.p.m. with which depths of about 2,300 ft. can be reached. For much greater depths, or where specially rapid auxiliary operations are desired, motors of 100 to 125 h.p. should be employed.

For the drilling itself a reversing motor is unnecessary as the crankshaft always runs in the same direction, but to meet the requirements of the auxiliary services the motors are equipped with reversing and speed-regulating controllers.

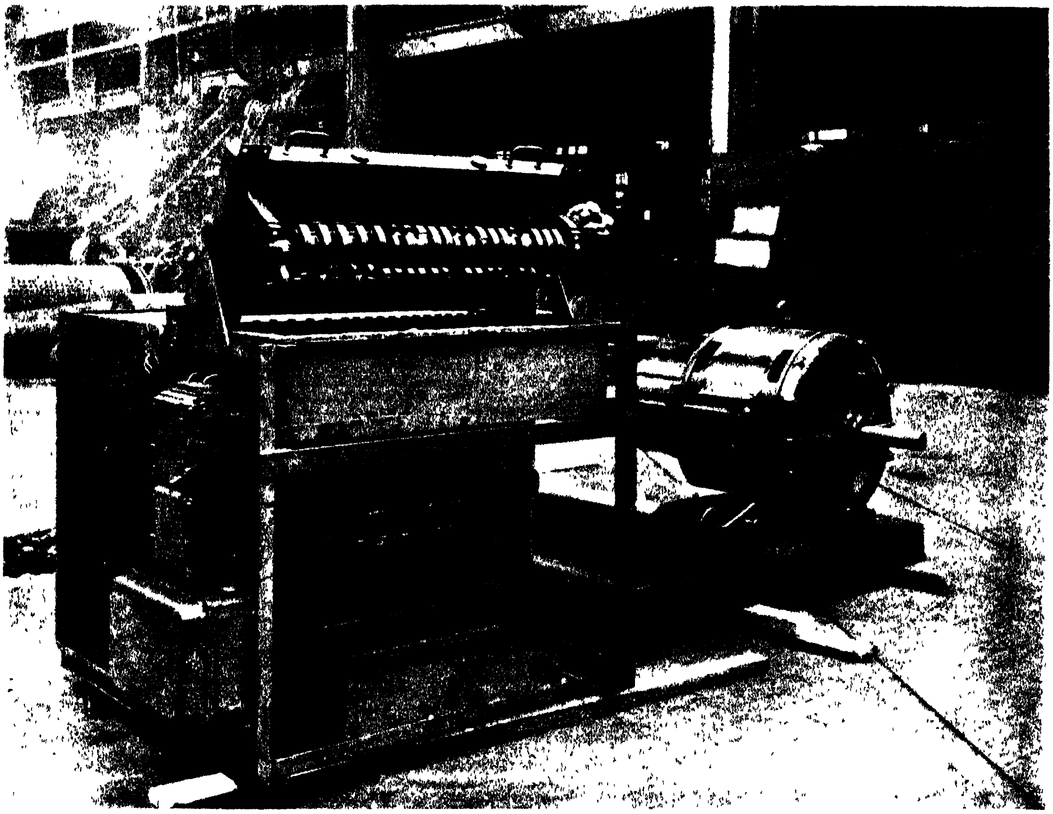


FIG. 1. Electric drilling equipment

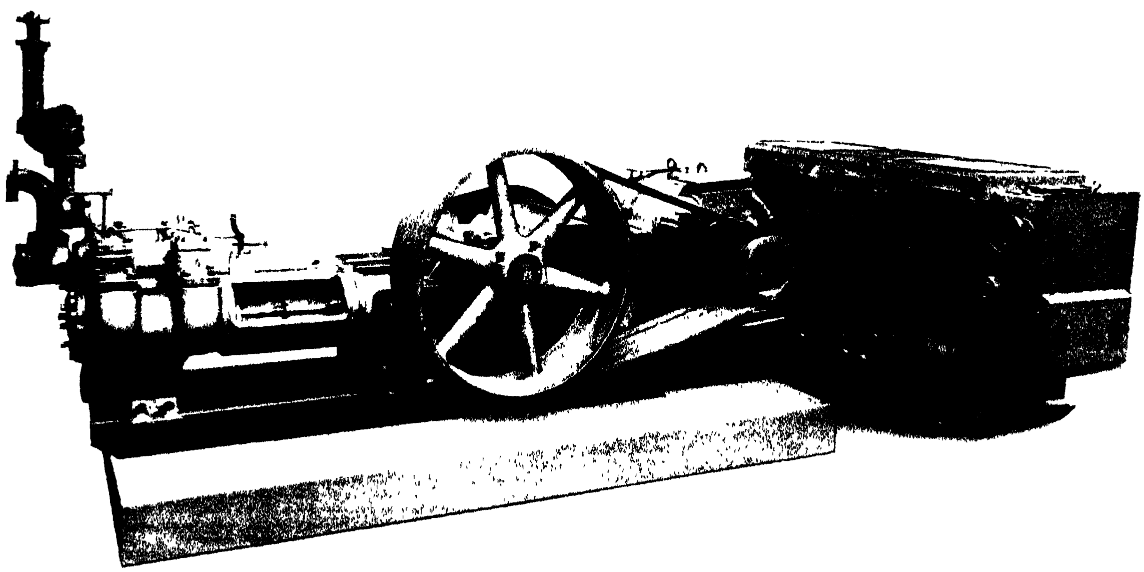


FIG. 2. Electrically driven mud pump and control gear.

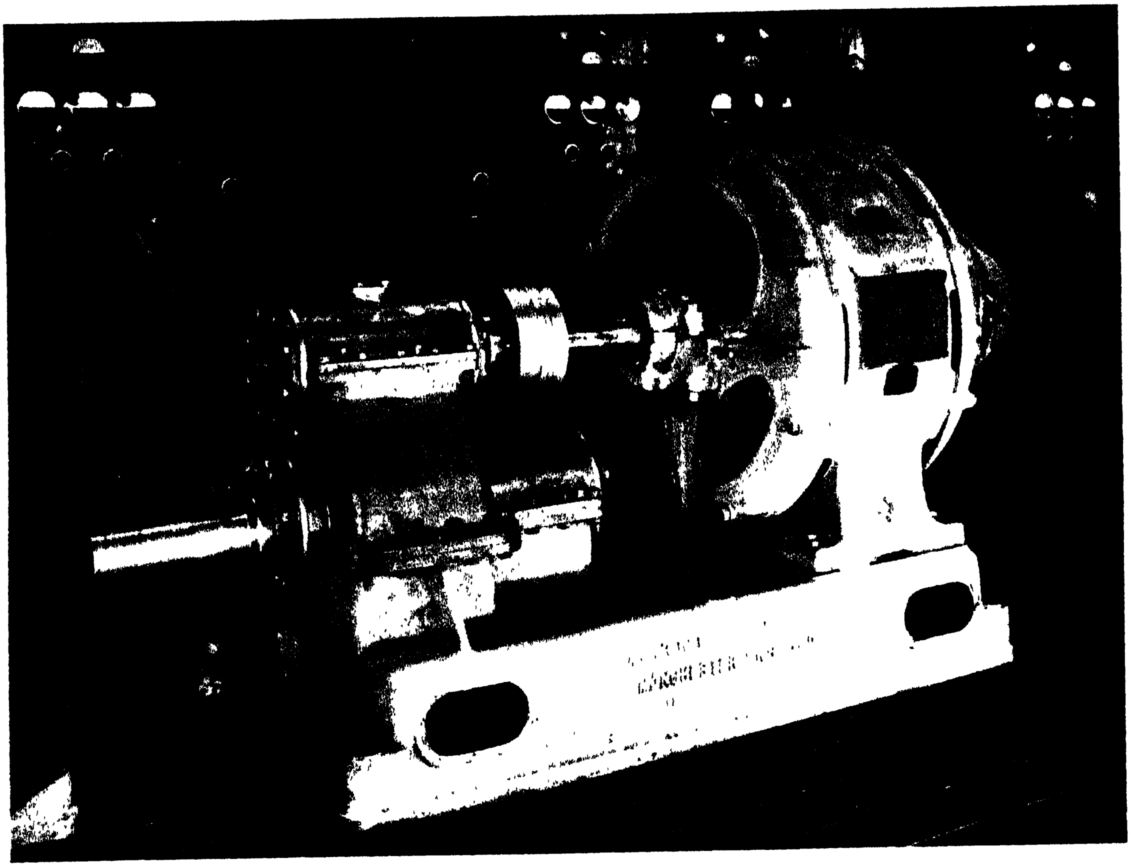


FIG. 3. 125-h p rotary drilling equipment

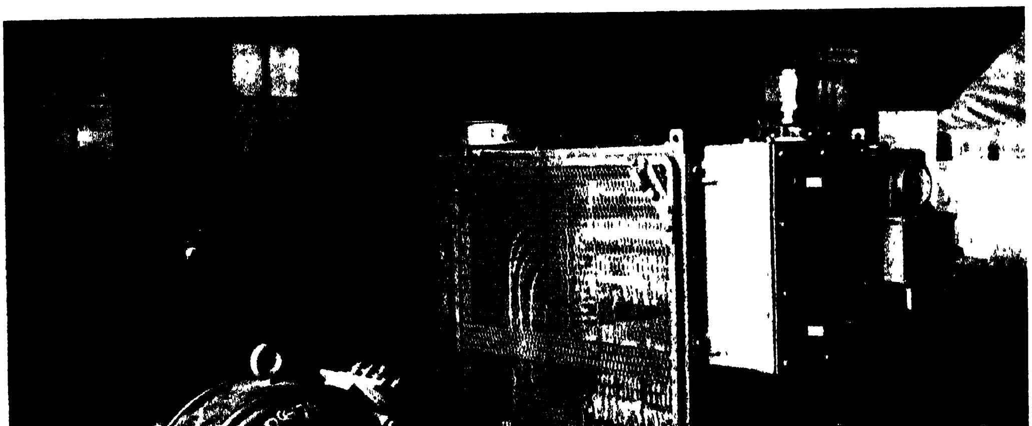


FIG. 4. Electric pumping equipment

As the depth increases the maximum number of blows at which the best progress will be obtained will decrease. With present designs a speed regulation of about 50% is desirable for good operation. For driving the rigs one controller is generally not sufficient, because the appropriate number of notches cannot be introduced, and, therefore, an auxiliary controller connected between the notches of the main controller should be employed.

For percussion drilling a twin-motor drive arranged for separate pulley drives or for single pulley and clutch connexion to one or two geared 40 h.p., 960/237 r.p.m. motors has been used on many oilfields with considerable success, the arrangement being that normally only one motor is used for drilling, but for hoisting the two motors are coupled together to deal with the heavier loading. As the well deepens the two motors coupled together are also used for drilling.

In addition to twin-motor drilling equipments, two-speed 35/75 h.p., 480/960 r.p.m. motors and control equipment are in use. For normal drilling the 35 h.p. connexion at 480 r.p.m. is used, and for hoisting the motor is connected to give 75 h.p. at 960 r.p.m.

In rotary drilling normal power requirements vary between 100 and 300 h.p., depending upon the size and condition of tools used, the depth of hole, the pressure of the bit on bottom, and the formations encountered, although peak loads of short duration are encountered in handling drill-pipe and casing. To meet these power requirements, drilling motors are specially designed to carry their full load continuously, and peak loads of several times their rating for short periods (Fig. 1).

Besides the wide range of horse-power required to meet drilling conditions, a wide speed range also must be available for carrying out necessary operations.

Hand-feeding of the bit is one of the most uncertain operations in rotary drilling. The torque on the drill-pipe, which is dependent upon the pressure of the bit at the bottom of the hole, is determined entirely by the experience and close attention of the operator. To maintain the torque on the drill-pipe within safe limits the automatic feed was introduced. Besides being a safety device it permits higher average cutting speeds, for there is always some pressure on the bottom. With automatic feed the pressure of the bit on the bottom and the speed of the rotary table are adjusted independently and maintained automatically.

This type of feed was concurrently developed by F. W. Hild of Los Angeles, California, and E. P. Halliburton of Duncan, Oklahoma, and used the same principle of a specialized combination mechanical differential and reduction gear for connexion to a standard draw-works.

As developed, the Hild drive is operated by two wound-rotor induction motors mounted with the gear on a common bedplate to form a single power unit. The Halliburton is operated by one prime mover, either an engine connected to the drive by the usual chain, or a motor operating through reduction gear and chain.

Automatic operation is dependent upon the condition that the downward feed of the drill-pipe is a function of the power required to rotate the bit on the bottom. This relationship is adjustable, and in the Hild system depends upon the relative speeds of the two motors, which speeds may be varied independently. In the Halliburton system the automatic feature is obtained by changes in sprocket ratio at different depths of the hole.

For the control of the motors what has been said for the percussion system applies with the rotary system, except that reversal of the drive is necessary to release the bit when stuck, as well as actual drilling. This reversal, depending as it does upon the nature of the rock, may very frequently have to be effected. Generally much depends upon the skill of the operator, as far as the greater or lesser stress of the equipment and its drive are concerned.

In rotary drilling a separate motor of from a 100 h.p. to 300 h.p., depending on site conditions and requirements, is used for driving the slush pump (Fig. 2). The motor speed is generally 750 r.p.m. Reversal is not necessary, but convenient adjustment of the pump output generally necessitates a speed regulation down to 50% A controller with seven or nine notches is usually sufficient, but for larger motors and 50% regulation, eleven notches may be required (Fig. 3).

One of the latest and most important developments in the drilling of oil-wells by the rotary method is the application of direct-current electric power for driving the drilling rigs and mud pumps.

The system employed for control is the variable-voltage system known also as the Ward-Leonard system. It has been widely applied for many years in other lines of industry, such as steel-rolling mills, large hoists, elevators, and boats.

Any type of draw-works drive should be able to develop extremely heavy torque at very low speeds for handling long strings of drill-pipe. It should also be capable of carrying comparatively heavy overloads at normal speed to permit handling drill-pipe expeditiously, and of operating considerably in excess of rated speed to allow handling the empty hook at the highest practicable rate.

The mud-pump drive should be capable of developing the normal torque required by the pump continuously at rapid speed, and should be able to develop high torques at reduced speeds. The speed should automatically drop off with increase in load, and if necessary it should stall at a value of torque which will not cause damage to the pump or gearing.

To meet the above requirements a type of drive has been developed in which power for the draw-works and mud-pump motors is furnished by individual direct-current generators operated by the generator-voltage system of control with characteristics similar to steam-engine drive.

The equipment consists of two direct-current generators with direct-connected exciters, driven by electric motors or internal-combustion engines; direct-current motors for draw-works and mud-pump drive; and the necessary control apparatus.

The generators are provided with a separately excited shunt winding and a series winding whose action opposes that of the shunt winding. This give the generators a 'drooping' voltage characteristic, i.e. causes the voltage of the generator, and hence the speed of the motors, to decrease with an increase in load. Open-type generators may be used, as the generating equipment can be located remote from the drilling rig. The motors are totally enclosed, and separately ventilated to exclude explosive gases.

The control equipment governs the speed and direction of rotation of the motors by varying the strength and polarity of the generator fields.

While drilling is in progress one generator furnishes power to the drilling motor and the other to the mud-pump motor. Changes in speed of either of the motors are made by regulating the voltage of the corresponding generator. With any fixed value of generator-field excitation the speed of the motor varies inversely with the load. This

characteristic is especially valuable in the case of the mud-pump drive, since any clogging of the line increases the load and reduces the speed of the motor, thereby calling attention to the trouble. The increased pressure thus developed will often clear the line, but even if the line is completely stopped the motor torque is limited. The result is that when an internal-combustion engine is used as a source of power the engine will not be stalled.

A movement of the transfer switch combines the capacity of the mud-pump generator with that of the drilling generator to supply power to the draw-works motor for hoisting heavy strings of pipe. When the generators are operated in this manner their separately excited fields are connected in series and controlled from the draw-works controller. This arrangement provides simultaneous identical control of the generators and correct division of load between them.

Provision is made in the control equipment for connecting either generator to the draw-works motor; therefore in case of the failure of one generating unit, it is possible to 'come out of the hole' slowly by using the other unit alone.

The exciters of these equipments are made with extra capacity to provide current for lights and auxiliary power, including blowers which force air through the enclosed, vapour-proof motors on the rig to keep them cool and to eliminate the possibility of electric sparks igniting any gas which may be encountered in the well.

To provide the greatest safeguards against the possibility of fire, &c., generating plant and control switches in the main variable-voltage control panel are located at a distance from the well. The motor control, which is oil immersed and flameproof, is, of course, placed on the rig.

After completion of the drilling, in cases where the well is not a 'gusher', a special pump shaft is introduced in the well. Its lowest section is perforated and acts as a suction pump. Above this suction pipe is a pump piston with non-return valve, generally designed as a ball valve. Below the piston is a foot valve. The operation of the pump is the same as that of other reciprocating pumps, and the amount of oil raised depends upon the stroke and the diameter of the piston.

The number of strokes varies between about 10 and 30 per min., and the length of stroke between 8 and 40 in. The fewer the number of strokes, the more even the operation of the pump and the less the risk of the rod breakages, which are specially liable to occur at great depths with correspondingly long rods.

The pumps run uniformly with practically constant energy demand, as the weight of the rod, &c., is compensated by counter-weights.

The operation of the pump is effected in the same way as for boring in the percussion system, by employing a beam placed over the well. The beam is driven by a crank through rods. The drive is sometimes effected by a belt pulley whose shaft operates the crankshaft through gearing. The electric motor drives the belt pulley of the pump drive direct, or through gearing, fixed on a common bedplate with it. In other cases the motor is placed on the beam foundation and then drives the crankshaft through double reduction gear.

For beam pumping 3-phase motors are used for operation on either 60 or 50 cycles and are generally 6/12 pole with synchronous speeds of 1,200/600 r.p.m. on 60 cycles and 1,000/500 on 50 cycles. The usual size on either frequency is about 35/15, although, of course, this can only be determined after an examination of the site conditions regarding amount of swabbing work and well output required (Fig. 4).

No rule is available for determining the motor capacity necessary for pumping, and this is generally based on experience or any data which may be available. The power required is affected by the depth of well, the size of pump, the pumping speed, and length of stroke, the gravity of the oil, and the amount of sand, gas, and water in it.

It may be said in general that under average conditions a rating of 15 h.p. is ample for pumping the majority of wells with plenty of margin to cover a temporary increase in load due to the varying conditions in the well. Wells to a depth of about 3,500 ft. can in most cases be handled by a 35/15 h.p. motor, but beyond this depth a larger two-speed motor is required.

The capacity of the motor required at high speed is determined by the loads to be lifted. Sometimes the pumping load determines the size of motor, and in other cases the sizes and weight of rods and tubing and the conditions under which it is handled fix the size of machine.

As a general rule the 35/15 h.p. two-speed motor and larger sizes will successfully handle all ordinary swabbing and bailing work and also a light string of drilling tools for cleaning out a well, and no change in pulley or other parts of the equipment will ordinarily be necessary.

A controller for reversing service, a regulating resistance, a pole-changing switch, a circuit breaker with overload protection are necessary for the control of an oil-well electric motor on all duties at both speeds. The motor has a 6-phase rotor with 6 collector rings which carry the secondary current at both speeds. This design requires no pole-changing connexions for the rotor winding, but a controller is used which regulates the resistance in all 6 secondary circuits. The operation of the controller is the same on either speed of the motor.

The same resistance is used for operation on both speeds of the motor, the ohmic resistance and the current capacity being so proportioned as to meet all the service requirements.

A small push-button contactor or hand-operated switch is generally used for changing the number of poles of the motor to obtain the high and low speeds.

The pumping motors and control equipment must be of the flameproof and explosion-proof type.

For light, shallow wells requiring infrequent cleaning 3, 5, 7½, 10, and 15 h.p. squirrel-cage motors operating on individual geared pumping jacks may be used to advantage. This range of ratings permits operating the motors at near rated load with resulting high efficiency and power factor. This equipment, which requires the use of separate portable cleaning apparatus, has a lower first cost than two-speed oil-well motor installations for each well, but does not have the same flexibility.

When the production of wells has declined to so low a point that it is uneconomical to pump them individually and they can be pumped at constant speed, they are usually equipped with pumping jacks and operated in groups from a central-driven pumping 'power', where contour of the country permits.

In some cases constant-speed squirrel-cage motors may be suitable, but in general wound-rotor motors with suitable controllers should be used.

It is difficult to predict the motor capacity required per well. It will vary with the depth of well and the other factors which also affect beam pumping, and it is also dependent upon the degree of counterbalancing obtained.

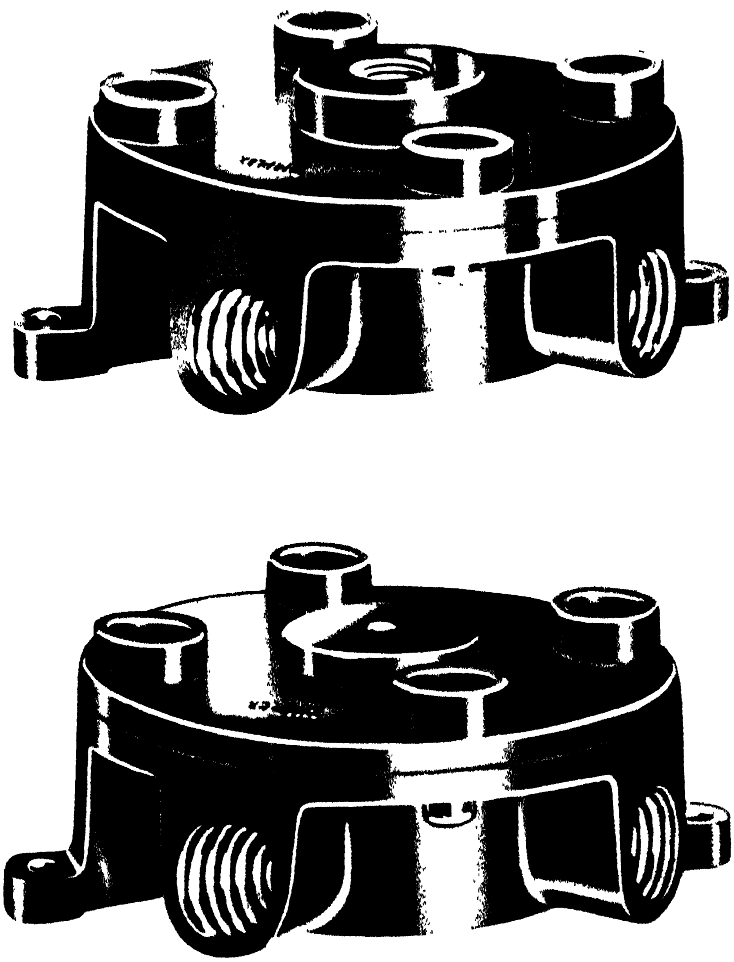


FIG. 5 Flameproof conduit boxes

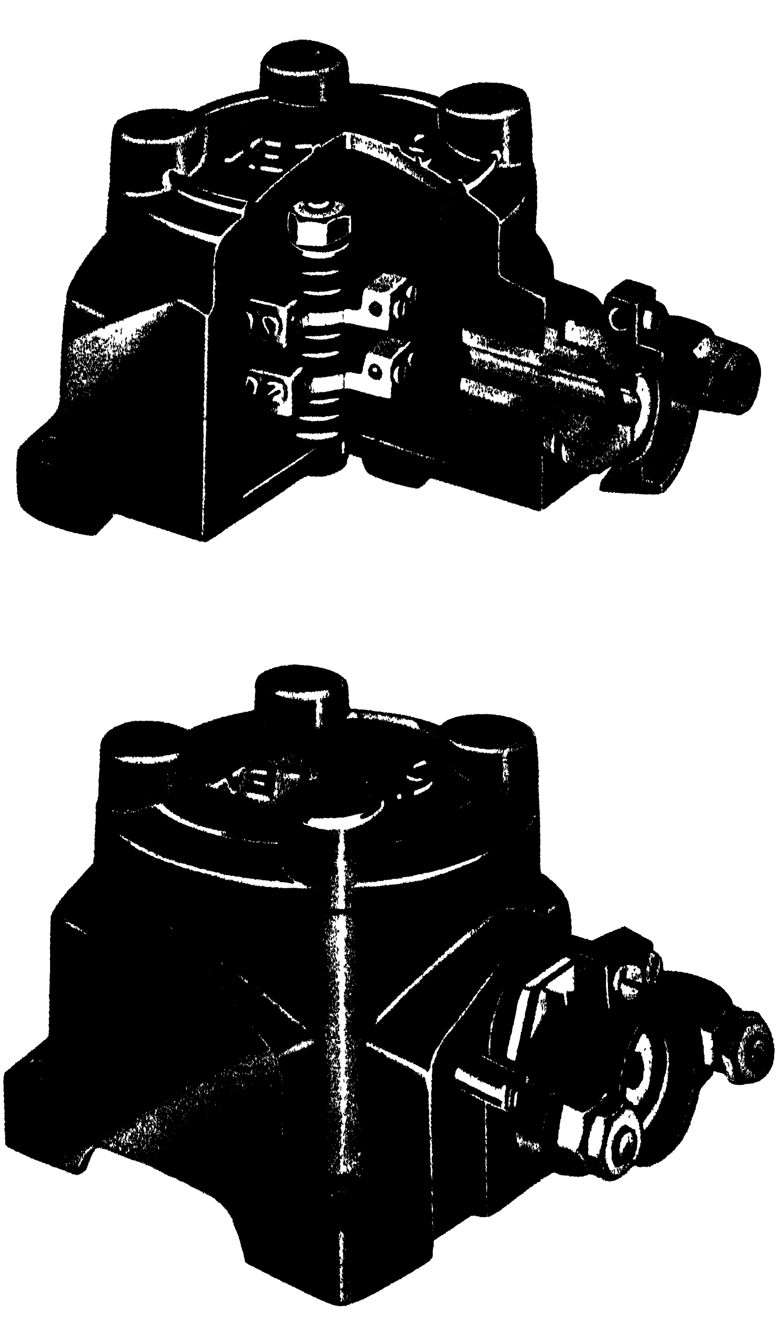


FIG. 6. Flameproof junction boxes for armoured cables

In shallow territory the wells require 1 h.p. to 1½ h.p. each. These are light pumping wells. For heavier wells, as high as 3 h.p. per well is required.

The motor is usually belted to a countershaft and the latter to the hand wheel of the pumping 'power'. Some types of power are geared and the motor is belted directly to its pinion.

Where wells are operated by individual motors of either the two-speed wound-rotor type or the single-speed squirrel-cage type, it is often advisable to provide for starting and stopping automatically at predetermined times. This is made possible by using switch gear and some form of electrical time switch.

Recently a submersible pumping unit has been developed. This pump unit consists of an electric motor which is direct-coupled to a pump. The unit, which is dimensioned to suit the internal diameter of the casing, is suspended from the delivery pipe and sunk below the oil-level. The motor is enclosed in an explosion-proof casing to prevent the ignition of inflammable gases.

Air and gas lifts when applied to the production of oil-wells involve the use of squirrel-cage or wound-rotor motors and control of a horse-power suitable to meet compressor sizes.

The success of a few pumping stations electrified several years ago has caused a rapid expansion in the applications of electricity to pipeline pumping.

On account of their high operating speeds, centrifugal pumps are particularly suitable for direct connexion to electric motors.

From the standpoint of economy in first cost and in operation, electric drive is very suitable for centrifugal pipeline pumping, and if desired remote control operation is possible with resultant saving in operating attendance.

In cases where it is desired to increase the capacity of an existing pipeline at minimum cost, the new Rannet pipeline pumps will efficiently meet the requirements. This pump was invented by President Dan Moran and E. O. Bennett, Chief Engineer of the Continental Oil Company, for use on the Great Lakes Pipe Line Company's Gasolene Line, and the capacity of the line was increased from 27,000 to 34,000 bbl. daily at a minimum of expense.

A totally enclosed motor-driven centrifugal unit, it is installed out of doors and no pump-station buildings are required. The booster unit, to increase throughput as above, is only 17 ft. long and 48 in. in diameter.

Enclosed by two metal shields, which are both dust- and moisture-proof, is a 700 h.p. motor directly connected to the 8-stage centrifugal pump. Upon entering the pump the gasoline flows around the motor and through the first four stages of the pump. The direction of flow is then reversed to allow the gasoline to pass through the second four stages. This arrangement eliminates thrust on the shaft, and forms a perfect hydraulic balance.

One of the most interesting characteristics of the unit is the method whereby the motor is cooled. Instead of making use of the ordinary air-cooling system, arrangements have been made for the incoming gasoline, as it enters the unit on its way to the pump, to flow between the double-walled stator housing enclosing the motor. The constant flow of the cold, incoming gasoline maintains an even, safe temperature at all times. The 700 h.p. motor is of 2,300 volts, 3-phase, 60-cycle design of 3,600 r.p.m., coupled direct to the pump.

The unit is designed to be operated by supervisory control, and can be entirely controlled from a central station several miles away.

Many other combinations have been used for main-line pumping, including self-contained Diesel engine direct-current generators, whereby with a combination of series and parallel operation and using direct-current motors variable conditions have been met.

It is important to construct all parts of the installation so that repeated explosions may take place without interfering with their operation and without permitting flame to escape and ignite the vapour-charged atmosphere.

Apparatus designed to meet the conditions of this class of service is more expensive than that for use in ordinary locations. It is therefore customary to segregate as far as possible the hazardous from the non-hazardous areas and provide materials and equipments accordingly.

For installation in hazardous areas, solid drawn conduit with threaded joints must be used. In the use of threaded joints it is necessary that the pipe enters the box or coupling to a required depth in order to make an acceptable flameproof joint (Fig. 5).

Special flameproof connexion boxes for conduit wiring should be used, in order to maintain the whole system as a flameproof enclosure. These boxes provide a safe and efficient method of making connexions between solid drawn conduit runs.

The flameproof connexion boxes should be heavily constructed in cast iron. Substantial covers are attached with shrouded box-spanner operated hexagon-headed brass bolts. The surfaces of both the box and cover should be accurately machined, giving a flameproof joint of required width.

Outlet boxes, junction boxes, switch cases, &c., must be constructed to withstand the maximum pressures that may occur within them.

Arcing apparatus such as switches, circuit breakers, or control apparatus must be of the flameproof type fitted with a special sealing terminal box to which the conduit is coupled.

Whilst most regulations permit the use of fuses if installed in flameproof enclosures, the necessity of removing covers for access to and replacement of blown fuses renders it important that flameproof fuse boxes should be fitted with an interlocked switch to ensure that the circuit is made 'dead' and remains so as long as the cover is open. This eliminates the possibility of a fuse blowing when the cover of the flameproof box is open.

Considerable progress has now been made in the design of small circuit breakers of the thermal overload, and other types, and these may be used instead of fuses and can be reset by means external to the flameproof box without the necessity of removing covers. This type of unit has many advantages, and will in due course replace the ordinary type of fuse.

Although conduit systems are in general use to-day, there is no doubt that in the near future these will be replaced by lead-covered and armoured systems when further developments have taken place in the provision of 2- and 3-core armoured cables of reasonable dimensions and flexibility (Fig. 6).

With an armoured system having suitable glands on the boxes and fittings an improved flameproof installation will be available, and certain of the troubles experienced with conduits, such as condensation resulting in many cases in the destruction of the internal wiring, will be eliminated.

The lantern of a typical flameproof-lamp fitting consists

of a heavy cast-iron body with heat dissipating fins. A special heat-resisting well-glass (individually tested to withstand a pressure of 75 lb. per sq. in.) is cemented into a cast-iron flange which is connected to the body by a wide machine-faced joint and shrouded bolts requiring a box spanner for removal (Fig. 7). The lantern is mounted on a flameproof connexion box, which is wired in fireproof flexible to the lampholder terminals (Fig. 8). A special design of bakelite lampholder, having solid moulded contacts, is fitted to provide a flameproof connexion between the lamp and the connexion chamber.

Flameproof combined switch and sockets for use with flameproof portable lights must be constructed so that it is impossible to withdraw the flameproof plug until the switch is in the 'off' position.

In general all electric-lighting installations should be given careful study and the exact amount of illumination provided for each particular area or plant.

Apart from reducing the number of accidents due to bad lighting, this procedure will definitely permit of increased efficiency in operation.

In concentrated networks slight differences in voltage or phase angle between feeders create unbalanced feeder loads. The use of current-balancing transformers gives good current distribution and improved voltage regulation for electric-lighting circuits.

As a general rule balancing should take place at individual local distribution points in preference to a main distribution centre such as a sub-station, &c.

The importance of having alternative supplies for the electric lighting of units such as cracking plant control rooms, &c., is generally appreciated, and in many cases emergency battery equipment is installed. This entails difficult maintenance and charging. It has been found that steam-generating plant is entirely reliable, and does not require so much attention as a battery installation.

Stone's Locomotive Turbo Generator, which has been successfullly used for this purpose, is an inductor alternator producing alternating current, and is more simple in design than any direct-current machine, as commutator, brushes, brush gear, field coils, and rotating-armature windings are entirely dispensed with.

The magnetic field of the alternator is produced by permanent magnets, while the only windings are two small stationary coils embedded in slots on the laminated pole faces.

The rotating portion of the generator consists of a bare toothed core of iron laminations carrying no windings. It performs the function of varying the intensity of the magnetic flux through the coils on the fixed poles and thus produces a flow of current.

The generators are designed for an output of from 350 to 1,000 watts.

The generator is connected to any convenient steam supply, and in case of emergency the steam valve to the turbo set is opened and the emergency lights immediately illuminated.

Apart from a main switch and fuse no further switches or protection are required or desired, as the load must be constant, otherwise difficulty will be experienced with the turbo governing.

The use of portable hand lamps in certain units, operated direct from supply mains, is liable to prove extremely dangerous.

Hand-lamp transformers are now available, which reduce the input voltage to 12 volts. The transformer is of the double-wound type, so that there is no possibility of the user coming into contact with any higher potential than 12 volts.

Hand lamps in dangerous areas should be of the flameproof type.

Flameproof miners' electric hand lamps as used for tank dipping, &c., give not less than 1 candle-power at the end of 9 hours' use. They are fitted into a 2-volt acid or a 2·5-volt alkaline battery. More light can be obtained, but only at the expense of added bulk and weight, and it is always a debatable point whether the advantage of additional light is worth the handicap of added weight.

Floodlighting is effective for use in extremely gassy locations, such as drilling wells, tank farms, cracking plant, and distillation units, and for facilitating loading operations. Various sizes and types are available, and to obtain most satisfactory results all floodlighting schemes should be developed by experts in this class of work.

For road lighting and general illumination the new mercury and sodium vapour lamps will undoubtedly be utilized to a great extent with improved and more efficient results.

In the oil industry electric welding has become a useful agent in the construction of pipelines, making manifolds, constructing cracking and distillation plants, building tanks, and carrying out general maintenance.

For general welding work, 300-, 400-, and 500-amp. portable welders meet the requirements. These can be alternating- or direct-current units, the former being of the transformer type, whilst the latter can be of the motor-generator type, or where no supply mains are available, engine-driven direct-current generators are used.

Welding consists of connecting the work to one pole of a suitable source of current and a metal wire or electrode to the other, and striking an arc between them so that both become fused. The diameter of the wire is chosen so that it is sufficiently heated by the arc to melt relatively quickly, and if correctly manipulated fills between the two parts to be joined. Arc welding with a carbon rod is generally only used for very rough work, particularly when filling rather than joining is the object.

The quality of the weld depends upon the type of the electrode used, and the arc itself. This latter depends upon the characteristics of the source of current and to a great extent upon the skill of the welder.

In view of the strenuous nature of welding work, it is important in cases where engine-driven generators are used that the engine should be liberally rated, otherwise engine failures will lead to excessive maintenance and loss of machine whilst the frequent repairs are being carried out.

Radiology has many useful applications in the inspection, examination, and investigation of welding processes. The fact that a radiograph reveals internal defects in a metallic structure confers unique value on the method.

Transportable X-ray sets are obtainable, which are both safe and robust and flexible in operation. Such an apparatus as this is capable of examining steel structures up to a thickness of 3 in. to 4 in.

Radiology has now achieved an important part in welding activity in practical inspection work, its chief claim to importance being that the structure after examination is unharmed. At the same time, radiographic results if obtained by properly trained operators are absolutely reliable and lend themselves to extremely accurate interpretation.

Communication systems are of great importance in the operation of oilfields, pipelines, and refineries, and it is now

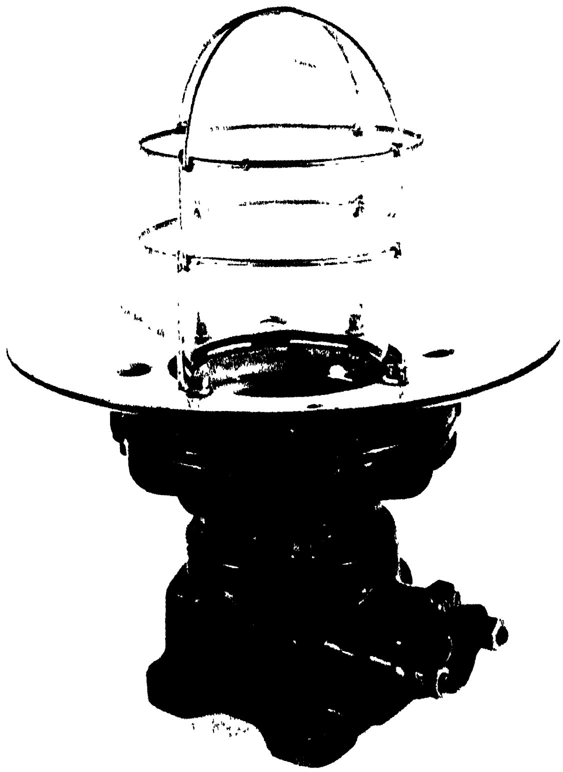


FIG. 7. Flameproof electric fitting for armoured cable

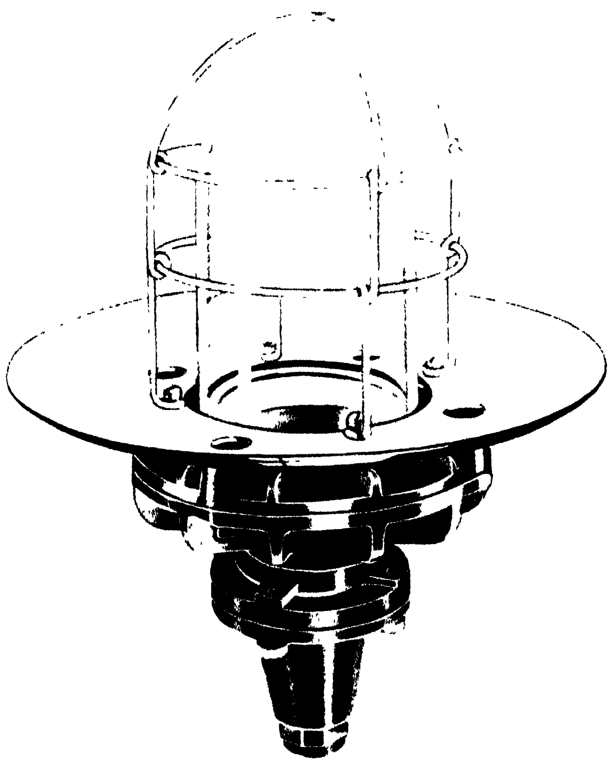


FIG. 8. Flameproof electric fitting for conduit

general practice to install automatic telephones to link up all operations, using magneto-telephone portable sets for pipeline maintenance.

Teleprinters have now to a considerable extent displaced the ordinary telegraph units, and have been found to be entirely satisfactory.

In cases of pipeline telephone systems consisting of comparatively long lines, the problem of making the metallic circuit yield communication facilities over and above the physical circuit normally available can best be dealt with by providing carrier-current apparatus.

In carrier-current telephony the voice frequency currents are caused to modulate a high-frequency current which serves as a carrier for the message. In this way an additional telephone channel is obtained using frequencies entirely above those transmitted in connexion with the ordinary voice frequency channel. By using other high frequencies several additional messages can be transmitted simultaneously on the same pair of wires, provided the line has been specially designed for such working.

No books have been published dealing specifically with the general electrification of oilfields and refineries, and the data forming the substance of this article has been accumulated from various sources.

SECTION 14

THE MEASUREMENT OF OIL, GAS, AND WATER IN OILFIELDS

THE GAUGING AND MEASUREMENT OF LIQUID PETROLEUM PRODUCTS

By HAROLD MOORE, M.Sc., F.C.S., M.Inst.P.T.

Consulting Petroleum Technologist

THE measurement of petroleum liquids may be divided into three sections: the calibration of the tanks, the operation of gauging the liquid, and the methods employed for the calculation of weight or volume.

Calibration of Oil Containers.

The containers employed for the bulk storage of liquid petroleum products are most frequently constructed of mild steel. Large land storage tanks are usually constructed in the form of a vertical cylinder, small rectangular tanks and horizontal cylinders are frequently employed, while spherical or spheroidal tanks are occasionally employed for the storage of petroleum products under pressure.

When oil is transported in bulk by ships or barges, the containers may be of two types. Firstly, a portion of the hull of the tanker or barge may be subdivided into a series of compartments, the oil being carried in contact with the shell of the vessel. Such tanks are commonly known as 'skin' tanks. Alternatively, tanks, usually either cylindrical or rectangular in shape, may be placed in the holds of the vessel, there then being a space between the sides of the oil tanks and the inside of the hull. Specially constructed tank vessels are also known, wherein both systems are employed.

All land-storage tanks should preferably be measured after a water test, when the tank plates will have received their initial stretch. Steel tapes, ½ in. wide, graduated in feet, inches, and tenths of an inch, and up to 200 ft. in length, are frequently used in this country, it being found in practice that a tape of this width is not seriously obstructed by the rows of rivets, and that a length of 200 ft. or less is convenient to handle.

It is rarely found that two tanks give identical measurements, though they may have been manufactured to the same drawings and templates. Therefore, where accuracy is essential, as for the purchase or sale of oil, it is necessary to measure each tank independently after erection.

Vertical Cylindrical Tanks.

Fig. 1 gives a typical arrangement of the plates of a vertical cylindrical tank, and illustrates the measurements required. It is more usual to take circumferential measurements or 'straps' than diameters. If diameters are taken a definite pull should be exerted on the tape, as the observed diameter must be corrected to allow for the catenary. It is somewhat difficult to maintain a definite tension on the tape, especially when working from ladders at the top tiers. Although both methods are in current use, the strapping method is more frequently employed at the present time.

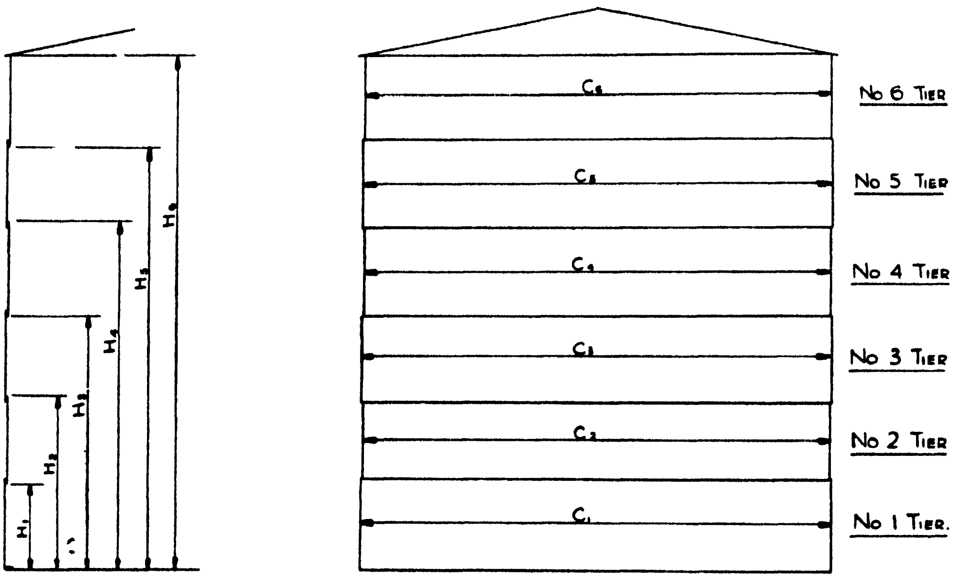


FIG. 1.

When taking circumferential measurements the first step is to mark each tier with chalk at points midway between the upper and lower edges, as noted by *C* 1, *C* 2, &c., in Fig. 1. The marks are placed in the centre of each plate and at each vertical joint. If the circumference of the tank exceeds the length of the measuring tape which is to be employed, it is next necessary to mark two or more vertical lines by means of a fine-pointed scriber. These lines are preferably marked at the centre of convenient plates, the distance between consecutive scribed lines being less than the length of the measuring tape. The tape is placed around the tank, and after ensuring that the tape is horizontal at the chalk-marks and quite taut, the distance between two scribed lines is measured. The tape is now moved around the tank and a further measurement is taken, which when added to the first reading will usually give the circumference of the tank, it being seldom necessary to take more

than two measurements when a tape 200 ft. in length is used. When the circumference of the tank is less than the length of the measuring tape, scribed lines are not necessary and a direct reading can be taken. A second set of readings should be taken on the same tier from a different starting-point; the result so obtained should be in close agreement with the previous reading. Each succeeding tier is measured in a similar manner.

When strapping in the manner described above, it will be found that the tape is not in contact with the tank shell at certain points owing to irregularities which raise the tape from the surface of the tank. At each vertical seam, for example, the tape will be raised from the tank shell over a distance known as the 'horizontal segment'. These distances must be measured wherever irregularities occur, the horizontal segment at a vertical seam being illustrated in Fig. 2. The vertical laps and plate thicknesses are also measured, the number of plates per tier being carefully noted.

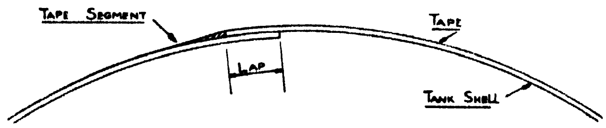


FIG. 2.

Vertical heights, as shown in Fig. 1, are next taken at one or more pairs of opposite points on the circumference, the average of these measurements giving the position of change of capacity at the commencement of each tier.

From the measurements previously described, it is possible to calculate the gross volume of the shell of the tank. In order to determine the net capacity it is necessary to make allowance for all 'additions' and 'displacements'. 'Displacements', frequently known as 'deadwood', include internal ladders, heating coils, bottom angles, roof supports if below the maximum liquid-level, and any other internal accessories which reduce the net capacity. 'Additions' include external manholes and other accessories which increase the net capacity of the tank. The 'additions' and 'displacements' must be carefully measured, the exact height of each item above the bottom of the tank being noted. When tanks are fitted with swing pipes it is usual to ignore the volume of the pipe, as this is usually full of oil and its position is not fixed. Allowance may be made, however, for the volume of the swing-pipe elbow, the position of which can be determined accurately. Whenever possible, it is advisable that plate thicknesses and measurements of 'additions' and 'displacements' should be compared with the tank-builder's specification or drawing.

The gross and net capacities of the tank are calculated in the following manner:

The formula employed for obtaining the gross gallons per inch for each tier is:

$$\text{Gross tier gallons per inch} = \tfrac{1}{4}\frac{C^2\times K}{\pi}. \qquad (1)$$

Deductions are made for the plate thickness, laps, and segments as follows:

$$\text{Plate gallons per inch} = C\times t\times K, \qquad (2)$$
$$\text{Laps gallons per inch} = W\times t\times N\times K, \qquad (3)$$
$$\text{Segments gallons per inch} = \tfrac{1}{2}L\times t\times N\times K, \qquad (4)$$

which can be combined into the following equation:

$$\text{Gallons per inch displaced} = (2C+2NW+NL)\times\tfrac{1}{2}t\times K, \qquad (5)$$

where C = circumference of tier in inches,
K = constant gallons per cubic inch,
t = plate thickness in inches,
N = number of plates per tier,
W = width of lap in inches,
L = length of tape segment in inches.

By subtracting equation (5) from equation (1), the net tier gallons per inch are obtained. The gallons per inch for the 'additions' and 'displacements' are now calculated and are entered on the calibration table in the correct position, so that the net tier gallons per inch can be calculated before computing the total capacity. The summation of the net gallons per inch is greatly facilitated by the use of an adding machine.

Bottom Allowances.

When vertical tanks are employed for the storage of light petroleum products, the tank bottoms are frequently covered with water. If it is decided always to maintain the water-level above the highest point of the tank bottom, it is not necessary to make allowance for bottom irregularities. This system, however, reduces the useful capacity of the tank and cannot be employed for the storage of products which would be damaged by the presence of water. When, therefore, it is not possible to employ water bottoms, it is advisable, and frequently essential, to determine the error resulting from bottom irregularities. It should here be noted that these irregularities seldom remain constant immediately after the erection of the storage tank, and it is therefore prudent to allow time for the tank to settle before taking the necessary measurements.

Various methods are employed for the measurement of bottom allowances, that most frequently employed being the measurement of a known volume of liquid contained in the tank. For light products, as, for example, motor spirit, white spirit, and kerosene, which give a clear line of demarcation between water and product, the following procedure is convenient:

Water is drained from the tank as completely as possible, using the facilities normally available. The tank is then filled to approximately half its total capacity with petrol, white spirit, kerosene, or similar product, the apparent volume in the storage tank, neglecting bottom irregularities, being ascertained by careful gauging. Water is then pumped into the tank until the highest point of the bottom is covered with water. The tank is again gauged and the height of water carefully measured, the net quantity of petroleum product in the tank is calculated and compared with the quantity previously ascertained. The difference between the net volumes so measured, taking into account any variations in temperature, is the bottom allowance. It should be noted that when this method is employed it is extremely important to ensure that the pipelines employed for pumping water into the tank do not contain any oil or similar product. When it is possible accurately to measure the quantity of water introduced into the storage tank, this measurement may be compared with the gauged quantity for comparison with the calculations mentioned above.

Where it is impracticable to use a water bottom, it is customary to transfer oil or water from another tank, which can be accurately gauged, into the tank being calibrated until the bottom is covered. Bottom allowances should be noted as separate items on the calibration charts, as these may be adjusted from time to time in the event of the bottom changing shape due to settlement of foundations.

Horizontal Cylindrical Tanks.

The calibration of horizontal cylindrical tanks is more difficult than that of vertical tanks, and various special features may complicate the work. Tanks of this type are often installed with their longitudinal axis slightly inclined to the horizontal, in order to facilitate drainage of water. Further, horizontal cylindrical tanks are frequently constructed with rounded or dished ends.

The actual work of measuring these tanks is comparatively simple: straps may be taken when the situation of the tank permits, but in practice it is found more satisfactory to take diameters (a large number of diameters can be taken to every one strap, thereby ensuring greater accuracy).

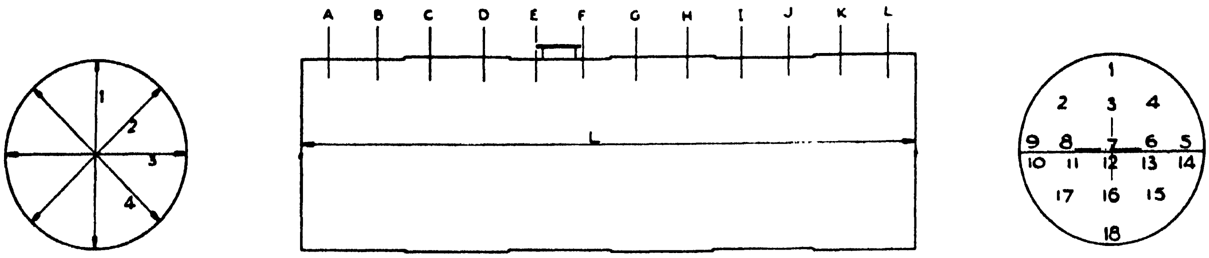


FIG. 3.

Fig. 3 gives the usual plating for a horizontal cylindrical flat-ended tank. The method of measuring by strapping is similar to that employed for vertical tanks, measurements being taken in the positions shown by the letters A, B, C, &c. When internal diameters are employed, four are taken at each section A, B, C, &c. The length of the tank is measured in a number of places, the actual positions are best decided by the operator taking the measurements; this remark also applies to the positions for straps or diameters. The 'additions' and 'displacements' are noted at the position where they occur.

The capacity of the tank in gallons is given by the equation:

$$V = \tfrac{1}{4}\pi \times D^2 \times L \times K, \tag{6}$$

where V = capacity in gallons,
D = average diameter in inches,
L = average length in inches,
K = constant gallons per cubic inch.

In practice it is found that horizontal cylindrical tanks are seldom truly circular, and when the cross-section of the tank varies noticeably from a true circle, special methods must be employed.

The capacity of the tank at any given depth H, Fig. 4, is the area of the segment depth H multiplied by the length of the tank.

$$\text{Area of segment} = D^2 \times M, \tag{7}$$

where M corresponds to various values of H/diameter and may be obtained from factor tables.

$$\text{Volume of segment in gallons} = v = D^2 \times L \times M \times K, \tag{8}$$

or, from (6) and (8),

$$v = \frac{4}{\pi} \times V \times M. \tag{9}$$

The table on page 681 gives values of M for each value of H/diameter, H being increased by equal increments until the complete depth has been calculated. The equation (9) is now used and capacities in gallons for the various values of the dip are calculated. Allowance is made for 'additions' and 'displacements' before completing the final net capacity table.

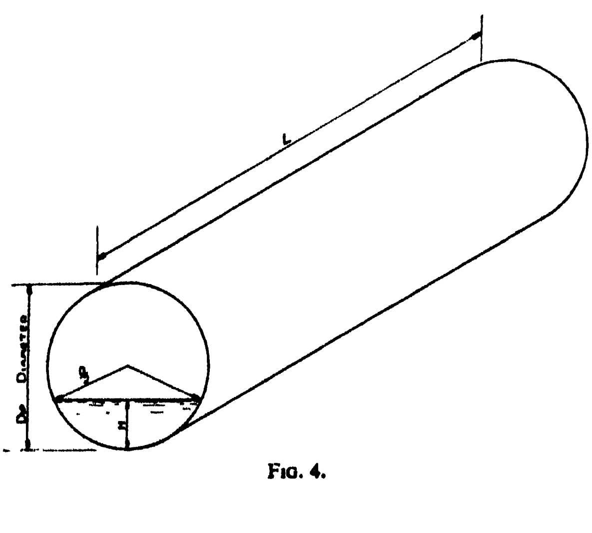


FIG. 4.

The methods employed for measuring the cylindrical portion of horizontal tanks having dished ends are similar to those already described, diameters or 'straps' being measured as for flat-ended tanks.

In order to measure the dished end, a thread is stretched across the tank, so as to form a datum line. Offsets from the thread to the dished end are measured at equidistant and known intervals, the process being repeated in each of the horizontal and vertical planes for both ends. The

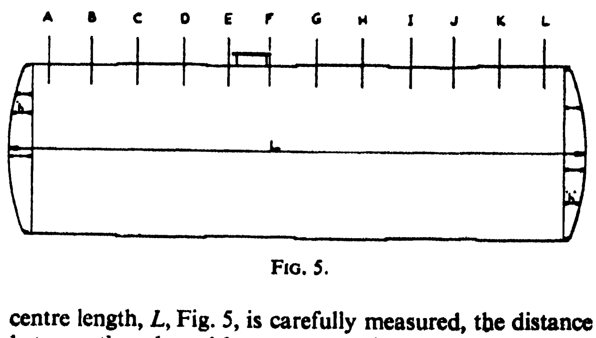


FIG. 5.

centre length, L, Fig. 5, is carefully measured, the distance between threads and between opposite points from which offsets have been taken are also measured for comparison with length L.

In order to calculate the capacity of each dished end, the offsets are plotted and the radius of curvature of the dished end is determined graphically. The internal diameters of the dished ends are measured and the depth of the dish is calculated from the following equation:

$$h = 2R - \frac{\sqrt{4R^2 - D_1^2}}{2}, \tag{10}$$

Circles: Areas of Segments

(Height = h; Diameter = D; Area = A)

h/D	A	h/D	A	h/D	A	h/D	A	h/D	A	h/D	A	h/D	A	h/D	A	h/D	A	h/D	A
		0·050	0·01468	0·100	0·04087	0·150	0·07387	0·200	0·11182	0·250	0·15355	0·300	0·19817	0·350	0·24498	0·400	0·29337	0·450	0·34278
0·001	0·00004	0·051	0·01512	0·101	0·04148	0·151	0·07459	0·201	0·11262	0·251	0·15441	0·301	0·19908	0·351	0·24593	0·401	0·29435	0·451	0·34378
0·002	0·00012	0·052	0·01556	0·102	0·04208	0·152	0·07531	0·202	0·11343	0·252	0·15528	0·302	0·20000	0·352	0·24689	0·402	0·29533	0·452	0·34477
0·003	0·00022	0·053	0·01601	0·103	0·04269	0·153	0·07603	0·203	0·11423	0·253	0·15615	0·303	0·20092	0·353	0·24784	0·403	0·29631	0·453	0·34577
0·004	0·00034	0·054	0·01646	0·104	0·04330	0·154	0·07675	0·204	0·11504	0·254	0·15702	0·304	0·20184	0·354	0·24880	0·404	0·29729	0·454	0·34676
0·005	0·00047	0·055	0·01691	0·105	0·04391	0·155	0·07747	0·205	0·11584	0·255	0·15789	0·305	0·20276	0·355	0·24976	0·405	0·29827	0·455	0·34776
0·006	0·00062	0·056	0·01737	0·106	0·04452	0·156	0·07819	0·206	0·11665	0·256	0·15876	0·306	0·20368	0·356	0·25071	0·406	0·29926	0·456	0·34876
0·007	0·00078	0·057	0·01783	0·107	0·04514	0·157	0·07892	0·207	0·11746	0·257	0·15964	0·307	0·20460	0·357	0·25167	0·407	0·30024	0·457	0·34975
0·008	0·00095	0·058	0·01830	0·108	0·04576	0·158	0·07965	0·208	0·11827	0·258	0·16051	0·308	0·20553	0·358	0·25263	0·408	0·30122	0·458	0·35075
0·009	0·00113	0·059	0·01877	0·109	0·04638	0·159	0·08038	0·209	0·11908	0·259	0·16139	0·309	0·20645	0·359	0·25359	0·409	0·30220	0·459	0·35175
0·010	0·00133	0·060	0·01924	0·110	0·04701	0·160	0·08111	0·210	0·11990	0·260	0·16226	0·310	0·20738	0·360	0·25455	0·410	0·30319	0·460	0·35274
0·011	0·00153	0·061	0·01972	0·111	0·04763	0·161	0·08185	0·211	0·12071	0·261	0·16314	0·311	0·20830	0·361	0·25551	0·411	0·30417	0·461	0·35374
0·012	0·00175	0·062	0·02020	0·112	0·04826	0·162	0·08258	0·212	0·12153	0·262	0·16402	0·312	0·20923	0·362	0·25647	0·412	0·30516	0·462	0·35474
0·013	0·00197	0·063	0·02068	0·113	0·04889	0·163	0·08332	0·213	0·12235	0·263	0·16490	0·313	0·21015	0·363	0·25743	0·413	0·30614	0·463	0·35573
0·014	0·00220	0·064	0·02117	0·114	0·04953	0·164	0·08406	0·214	0·12317	0·264	0·16578	0·314	0·21108	0·364	0·25839	0·414	0·30712	0·464	0·35673
0·015	0·00244	0·065	0·02166	0·115	0·05016	0·165	0·08480	0·215	0·12399	0·265	0·16666	0·315	0·21201	0·365	0·25936	0·415	0·30811	0·465	0·35773
0·016	0·00268	0·066	0·02215	0·116	0·05080	0·166	0·08554	0·216	0·12481	0·266	0·16755	0·316	0·21294	0·366	0·26032	0·416	0·30910	0·466	0·35873
0·017	0·00294	0·067	0·02265	0·117	0·05145	0·167	0·08629	0·217	0·12563	0·267	0·16843	0·317	0·21387	0·367	0·26128	0·417	0·31008	0·467	0·35972
0·018	0·00320	0·068	0·02315	0·118	0·05209	0·168	0·08704	0·218	0·12646	0·268	9 16932	0·318	0·21480	0·368	0·26225	0·418	0·31107	0·468	0·36072
0·019	0·00347	0·069	0·02366	0·119	0·05274	0·169	0·08779	0·219	0·12729	0·269	0·17020	0·319	0·21573	0·369	0·26321	0·419	0·31205	0·469	0·36172
0·020	0·00375	0·070	0·02417	0·120	0·05338	0·170	0·08854	0·220	0·12811	0·270	0·17109	0·320	0·21667	0·370	0·26418	0·420	0·31304	0·470	0·36272
0·021	0·00403	0·071	0·02468	0·121	0·05404	0·171	0·08929	0·221	0·12894	0·271	0·17198	0·321	0·21760	0·371	0·26514	0·421	0·31403	0·471	0·36372
0·022	0·00432	0·072	0·02520	0·122	0·05469	0·172	0·09004	0·222	0·12977	0·272	0·17287	0·322	0·21853	0·372	0·26611	0·422	0·31502	0·472	0·36471
0·023	0·00462	0·073	0·02571	0·123	0·05535	0·173	0·09080	0·223	0·13060	0·273	0·17376	0·323	0·21947	0·373	0·26708	0·423	0·11600	0·473	0·36571
0·024	0·00492	0·074	0·02624	0·124	0·05600	0·174	0·09155	0·224	0·13144	0·274	0·17465	0·324	0·22040	0·374	0·26805	0·424	0·31699	0·474	0·36671
0·025	0·00523	0·075	0·02676	0·125	0·05666	0·175	0·09231	0·225	0·13227	0·275	0·17554	0·325	0·22134	0·375	0·26901	0·425	0·31798	0·475	0·36771
0·026	0·00555	0·076	0·02729	0·126	0·05733	0·176	0·09307	0·226	0·13311	0·276	0·17644	0·326	0·22228	0·376	0·26998	0·426	0·31897	0·476	0·36871
0·027	0·00587	0·077	0·02782	0·127	0·05799	0·177	0·09384	0·227	0·13395	0·277	0·17733	0·327	0·22322	0·377	0·27095	0·427	0·31996	0·477	0·36971
0·028	0·00619	0·078	0·02836	0·128	0·05866	0·178	0·09460	0·228	0·13478	0·278	0·17823	0·328	0·22415	0·378	0·27192	0·428	0·32095	0·478	0·37071
0·029	0·00653	0·079	0·02889	0·129	0·05933	0·179	0·09537	0·229	0·13562	0·279	0·17912	0·329	0·22509	0·379	0·27289	0·429	0·32194	0·479	0·37171
0·030	0·00687	0·080	0·02943	0·130	0·06000	0·180	0·09613	0·230	0·13646	0·280	0·18002	0·330	0·22603	0·380	0·27386	0·430	0·32293	0·480	0·37270
0·031	0·00721	0·081	0·02998	0·131	0·06067	0·181	0·09690	0·231	0·13731	0·281	0·18092	0·331	0·22697	0·381	0·27483	0·431	0·32392	0·481	0·37370
0·032	0·00756	0·082	0·03053	0·132	0·06135	0·182	0·09767	0·232	0·13815	0·282	0·18182	0·332	0·22792	0·382	0·27580	0·432	0·32491	0·482	0·37470
0·033	0·00791	0·083	0·03108	0·133	0·06203	0·183	0·09845	0·233	0·13900	0·283	0·18272	0·333	0·22886	0·383	0·27678	0·433	0·32590	0·483	0·37570
0·034	0·00827	0·084	0·03163	0·134	0·06271	0·184	0·09922	0·234	0·13984	0·284	0·18362	0·334	0·22980	0·384	0·27775	0·434	0·32689	0·484	0·37670
0·035	0·00864	0·085	0·03219	0·135	0·06339	0·185	0·10000	0·235	0·14069	0·285	0·18452	0·335	0·23074	0·385	0·27872	0·435	0·32788	0·485	0·37770
0·036	0·00901	0·086	0·03275	0·136	0·06407	0·186	0·10077	0·236	0·14154	0·286	0·18542	0·336	0·23169	0·386	0·27969	0·436	0·32887	0·486	0·37870
0·037	0·00938	0·087	0·03331	0·137	0·06476	0·187	0·10155	0·237	0·14239	0·287	0·18633	0·337	0·23263	0·387	0·28067	0·437	0·32987	0·487	0·37970
0·038	0·00976	0·088	0·03387	0·138	0·06545	0·188	0·10233	0·238	0·14324	0·288	0·18723	0·338	0·23358	0·388	0·28164	0·438	0·33086	0·488	0·38070
0·039	0·01015	0·089	0·03444	0·139	0·06614	0·189	0·10312	0·239	0·14409	0·289	0·18814	0·339	0·23453	0·389	0·28262	0·439	0·33185	0·489	0·38170
0·040	0·01054	0·090	0·03501	0·140	0·06683	0·190	0·10390	0·240	0·14494	0·290	0·18905	0·340	0·23547	0·390	0·28359	0·440	0·33284	0·490	0·38270
0·041	0·01093	0·091	0·03559	0·141	0·06753	0·191	0·10469	0·241	0·14580	0·291	0·18996	0·341	0·23642	0·391	0·28457	0·441	0·33384	0·491	0·38370
0·042	0·01133	0·092	0·03616	0·142	0·06822	0·192	0·10547	0·242	0·14666	0·292	0·19086	0·342	0·23737	0·392	0·28554	0·442	0·33483	0·492	0·38470
0·043	0·01173	0·093	0·03674	0·143	0·06892	0·193	0·10626	0·243	0·14751	0·293	0·19177	0·343	0·23832	0·393	0·28652	0·443	0·33582	0·493	0·38570
0·044	0·01214	0·094	0·03732	0·144	0·06963	0·194	0·10705	0·244	0·14837	0·294	0·19268	0·344	0·32927	0·394	0·28750	0·444	0·33682	0·494	0·38670
0·045	0·01255	0·095	0·03791	0·145	0·07033	0·195	0·10784	0·245	0·14923	0·295	0·19360	0·345	0·24022	0·395	0·28848	0·445	0·33781	0·495	0·38770
0·046	0·01297	0·096	0·03850	0·146	0·07103	0·196	0·10864	0·246	0·15009	0·296	0·19451	0·346	0·24117	0·396	0·28945	0·446	0·33880	0·496	0·38870
0·047	0·01339	0·097	0·03909	0·147	0·07174	0·197	0·10943	0·247	0·15095	0·297	0·19542	0·347	0·24212	0·397	0·29043	0·447	0·33980	0·497	0·38970
0·048	0·01382	0·098	0·03968	0·148	0·07245	0·198	0·11023	0·248	0·15182	0·298	0·19634	0·348	0·24307	0·398	0·29141	0·448	0·34079	0·498	0·39070
0·049	0·01425	0·099	0·04028	0·149	0·07316	0·199	0·11102	0·249	0·15268	0·299	0·19725	0·349	0·24403	0·399	0·29239	0·449	0·34179	0·499	0·39170
																		0·500	0·39270

Rules for Using Table: (1) Divide height of segment by the diameter; multiply the area in the table corresponding to the quotient, height/diameter, by the diameter squared. When segment exceeds a semicircle, its area is: Area of circle minus the area of a segment whose height is the circle diameter minus the height of the given segment. (2) To find the diameter when given the chord and the segment height: the diameter = $[(\frac{1}{2}\text{ chord})^2/\text{height}]+$ height.

where, in Figs. 6 and 7,

R = radius of curvature of dish in inches,
D_1 = diameter of dish in inches,
h = depth of dish in inches.

If the dished ends are different in size, two values of h will be found, i.e. h_1 and h_2.

The length of the barrel of the tank, l, is given by

$$l = L-(h_1+h_2). \tag{11}$$

The capacity of the barrel is calculated as for a flat-ended tank, as described previously, and the gallons per inch ascertained.

The capacity of the dished ends, V_1, may be calculated rom either of the following equations:

$$V_1 = \tfrac{1}{6}\pi\times h\times K\times(\tfrac{3}{4}D_1+h^2), \tag{12}$$

$$V_1 = \tfrac{1}{6}\pi\times h^2\times K\times(6R-2h). \tag{13}$$

The method employed to split up the capacity of the dished end into gallons per inch for addition to the gallons per inch of the barrel is given below, the work involved being considerable.

Reference is made to Fig. 7, which shows a dished end. Section $AOBC$ is taken at the centre of the dish and section $A_1\,O_1\,B_1\,C_1$ at any depth H from the bottom of the dish.

D_1 = the diameter of the dish in inches,
R = radius of curvature of dish as found graphically in inches,
h = depth of segment in dish in inches,
r = radius of segment in inches of depth h,
$x = OP = O_1P_1 = r-h$ = constant in inches.

From Fig. 7 it is found

$$x^2 = R^2-(\tfrac{1}{2}D_1)^2. \tag{14}$$

$$r = x+h. \tag{15}$$

Also $\quad O_1B_1^2 = \left(\frac{D_1}{2}\right)^2 - \left(\frac{D_1}{2}-H\right)^2 = r^2-(r-h)^2$

Therefore $D_1H-H^2 = (x+h)^2-x^2 = 2hx+h^2$

or $\quad h^2+2hx+H^2-D_1H = 0,$

$$h = \sqrt{x^2-(H^2-D_1H)}-x, \tag{16}$$

or, by substituting (14),

$$h = \sqrt{R^2-(\tfrac{1}{2}D_1-H)^2}-\sqrt{R^2-(\tfrac{1}{2}D_1)^2}. \tag{17}$$

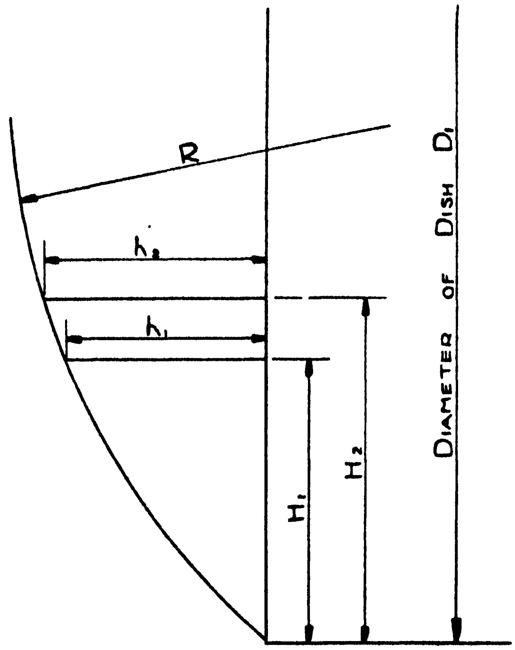


FIG. 6.

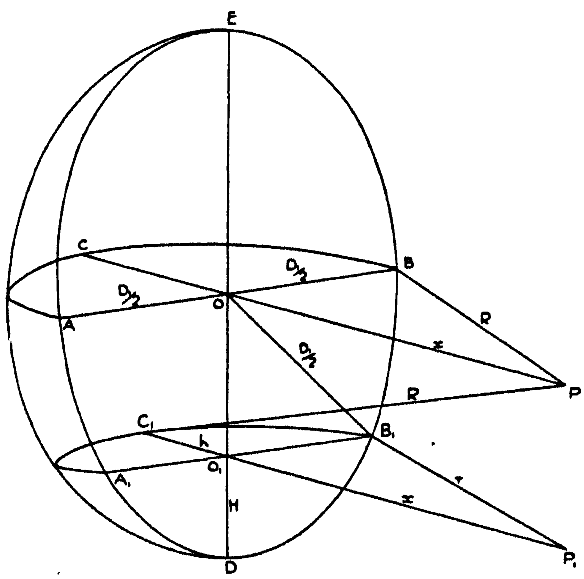


FIG. 7.

An equation has now been found from which the depths h_1, h_2, &c., of segments at heights H_1, H_2, &c., from the bottom of the dish are calculated and the diameter of each segment is found from

$$\text{Diameter of segment depth } h = 2(x+h). \tag{18}$$

At this stage it should be mentioned that the values of H_1, H_2, &c., are taken so that mean segment areas of depths h_1, h_2, &c., are found in order to avoid taking averages before making out the factor table.

The radius of each segment of depths h_1, h_2, &c., is found from equations (14) and (15), so that $h_1/2r$ can be found in order to obtain the values of M from the tables.

Gallons per inch at segment depth h_1

$$= 4\times r_1^2\times M\times K\times 1 \text{ in.} \tag{19}$$

This is repeated for all values of h_1 and r_1, and the sum of the results should equal the calculated capacity of the dished end. The gallons per inch for each segment are added to the gallons per inch of the barrel at corresponding heights; a further summation then gives the capacity of the tank at each inch of dip.

The calculations necessary for the calibration of horizontal cylindrical tanks which are not level but are sloping involve a very considerable amount of work. These computations are too complex for description within the scope of this article. Tanks sloping up to 6 in. in 30 ft. can be calibrated by measurement with fairly good results, but tanks at a greater slope are more satisfactorily calibrated by water. The position of the gauging hatch is a most important consideration, and if the position of the 'dip' is altered, the tank must be recalibrated.

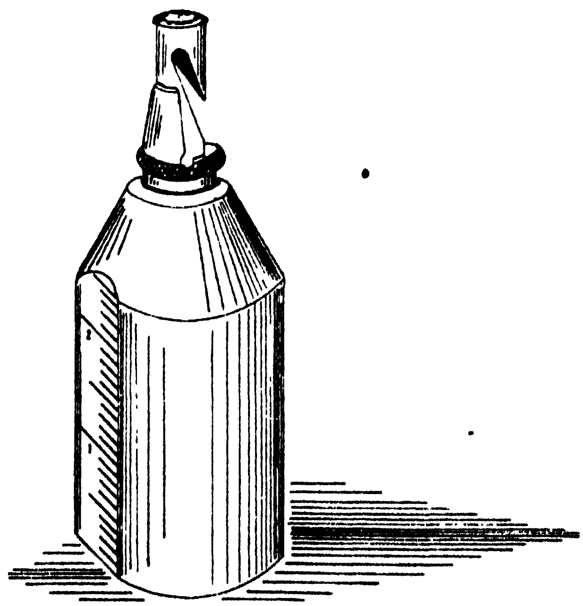
General Note.

In addition to the calibration of the storage tanks it is usually advisable to measure all oil pipelines in order that details of their capacity may be available when required.

Graphical methods are frequently employed for the calibration by measurement of 'skin' tanks in ships and barges. These methods, however, are too complicated for inclusion in this article. It is not possible to define any standard procedure, as the transverse sections vary considerably from fore to aft.

The Gauging of Liquid Petroleum Products

For commercial purposes it may be necessary either to determine the weight of a given quantity of liquid or to



4" DIP WEIGHT

FIG. 8.

measure its volume at a standard temperature. Both weight and volume are currently employed for commercial transactions, and on many occasions both measurements are required.

For the measurement of bulk quantities of liquids, however, it is almost always necessary first to determine the volume, the corresponding weight being computed from the density at the temperature at which the volume has been measured. When calibrated rail and road cars are employed, the weight may be ascertained by direct weighing or, alternatively, by gauging as desired.

Measurement of Volume.

Three different systems of measurement may be employed for determining the volume of oil contained in calibrated vessels: firstly, gauging or 'dipping'; secondly, ullaging, which involves the measurement of the distance of the liquid surface below certain fixed gauge points; thirdly, gauge glasses or float systems may be used.

The equipment usually necessary for gauging or 'dipping' storage tanks includes a steel tape suitably graduated, a dip weight of known length, a graduated water-finding rule, a sampling can, water-finding paste or paper, a thermometer, and sample bottles or cans. Figs. 8, 9, and 10 show types of dip weight, water-finding rule, and sampling can, which are commonly used. The tops of the dip weight and water-finding rule are so arranged that they can be clipped on to the ring at the end of the steel tape. The lengths of the dip weight and water-finding rule are accurately known, the length being measured from the bottom of the instrument to the lower edge of the tape ring when clipped on to the tape, and being usually a conveniently exact number of units. In Great Britain, for example, dip weights of exactly 4 in. and 7 in., and water-finding rules of exactly 12 in. in length are frequently employed. Occasionally the measuring tape is shortened by 4 in. or 7 in. in order that when the appropriate dip weight is used the tape reading shall not require any correction to allow for the length of the dip weight.

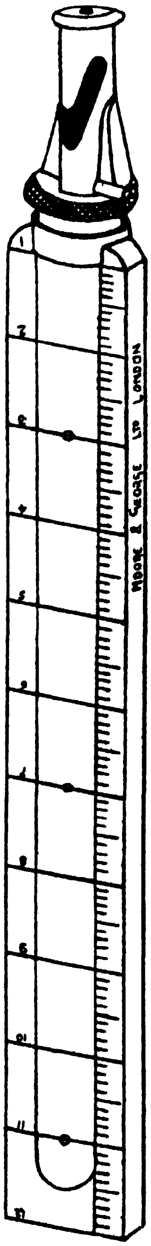


FIG. 9.

The special sampling can shown in Fig. 11 is such that a sample bottle can be placed inside the can, the cork can be withdrawn or reinserted by means of the cords, so that corked samples may be taken at any required position in the tank. This apparatus is particularly useful when sampling extremely volatile liquids.

Vertical oil-storage tanks are usually provided with one or more gauge hatches. Where more than one gauge hatch is fitted, these are preferably spaced equally in one or more circles, and may be combined with a centre-gauge hatch. Tanks in this country are frequently equipped with three

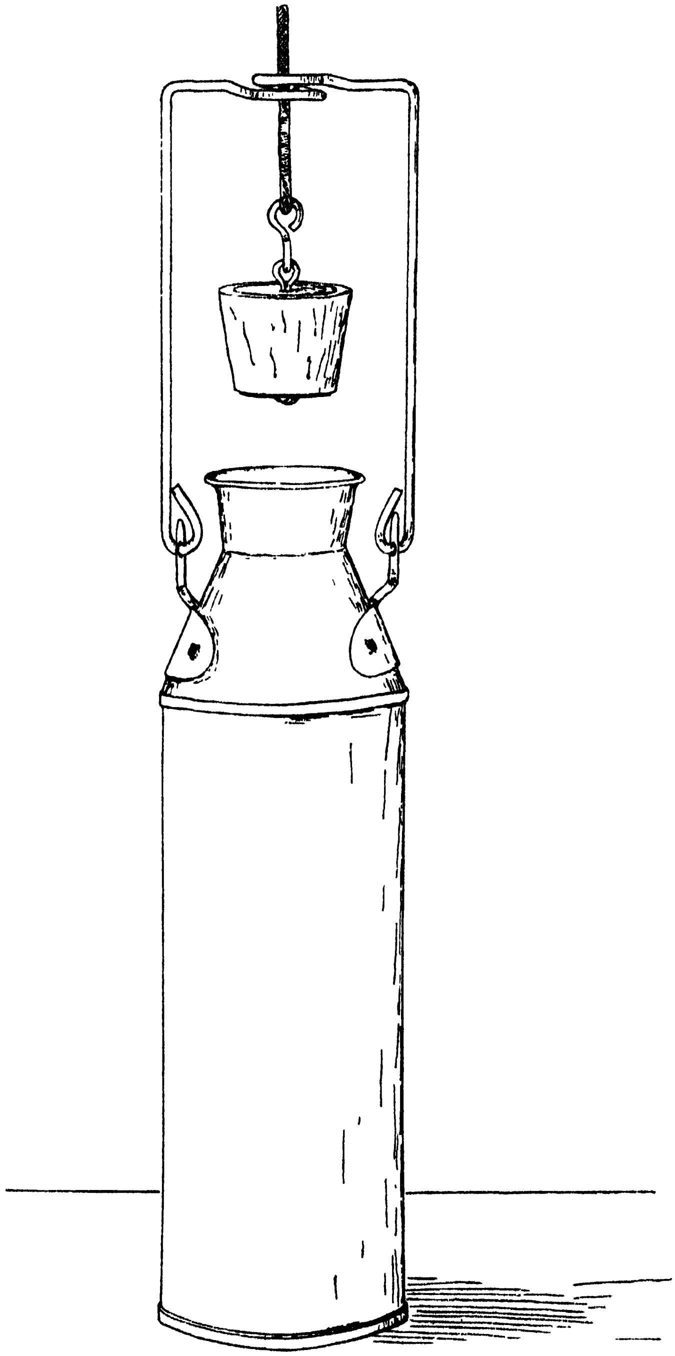


FIG. 10.

or four gauge hatches spaced at equal distances near the edge of the tank, combined with a centre-gauge hatch. Tanks of large diameter are, in addition, occasionally equipped with an intermediate series of gauge hatches equally spaced round a circle of diameter approximately half that of the storage tank. Such tanks, for example, may be fitted with four gauge hatches near the edge of the tank, a centre-gauge hatch and four gauge hatches midway

between the centre and the tank rim, making nine in all.

In order to measure the level of oil in the storage tank, the dipping weight is attached to the steel tape by means of the special fastening. The weight is then lowered through the gauge hatch by means of the tape, and after reaching the bottom of the tank the tape is rapidly withdrawn, the liquid-level being read from the graduated tape. It is naturally important that the tape should not be allowed to sag after the weight just touches the tank bottom. It should be noted, however, that when extremely viscous liquids are measured by gauging, the reading may be inaccurate if the tape is raised immediately after touching the tank bottom. Difficulty may also be experienced when extremely volatile liquids are measured, owing to the rapid evaporation of the liquid from the surface of the measuring tape. If, however, the tape be first wiped with a slightly oily rag, this difficulty is largely overcome. Chalk is sometimes employed in order to facilitate reading, but this practice is not to be recommended as certain liquids are apt to creep up a chalked tape, thus giving inaccurate results.

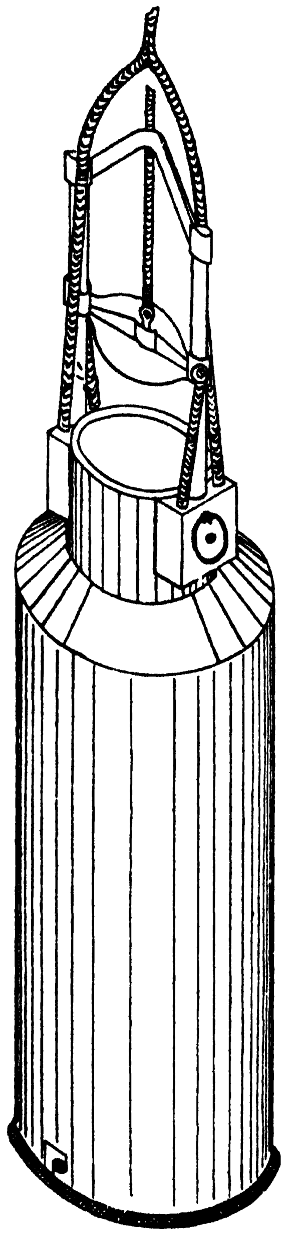


FIG. 11.

Gauge rods are occasionally employed for the measurement of small storage tanks, and in particular for horizontal cylindrical tanks. These rods may be graduated either in units of length or, alternatively, of volume; rods of the latter type being particularly useful when loading into small containers.

The apparatus previously mentioned is also required for measuring tanks by the method of ullaging, with the exception that the dip weight is not necessary. In addition an ullage rule must be employed, this instrument being conveniently combined with the water-finding rule previously mentioned, the combined instrument being illustrated in Fig. 9.

Ullage rules are engraved in units of length, commencing from the top in a direction opposite to that of the etchings on the tape. In order to measure the ullage, the rule is clipped on to the measuring tape and is lowered through the dip hatch until it touches the surface of the liquid. The rule is then further lowered until a convenient tape reading coincides with the ullage reference-point, which should be marked on the gauge hatch. The rule is withdrawn and the sum of the reading on the ullage rule and the reading on the tape is the required ullage. This method of measurement is frequently employed when tanks contain 'deadwood' which might foul a dip weight. For this reason ships' tanks and tanks with conical bottoms are usually ullaged. The method is also convenient for measuring liquids containing large quantities of sediment, or liquids from which solids are liable to separate. Ullaging is also sometimes employed for the measurement of liquids at extremely high temperatures.

The calibration charts of tanks which it is intended to measure by ullaging show the capacities corresponding to ullages taken either from a definite reference-point at the top of the tank or, alternatively, corresponding to the average of measurements taken from more than one reference-point. It is of the utmost importance that the reference-points from which ullages are to be taken should be permanently marked on the gauge hatches, and if the position of these points is changed the calibration chart must be adjusted accordingly. It will be obvious that the position of reference-points must be accurately known prior to the preparation of calibration tables.

While gauge glasses are not commonly employed in Great Britain, storage tanks are frequently so fitted elsewhere, particularly on the Continent. When gauge glasses are used it is important that the length of each individual glass should not be excessive, and the usual arrangement is to provide a series of short gauge glasses, so arranged that the maximum reading of one glass is greater than the minimum reading of the succeeding glass. Securely mounted close to the glasses is a scale graduated either in units of length or in units of volume. When gauge glasses are employed in conjunction with a scale which is capable of movement relative to the tank, bottom allowances can conveniently be made by adjusting the zero of the scale. For this purpose a measured quantity of liquid is passed into the tank, the zero of the measuring scale being adjusted until the gauge reading coincides with the exact volume of liquid contained. The scale is then permanently clamped into position. It is important to note that before reading gauge glasses it is advisable to empty the glass at least once, in order that the temperature of the liquid in the glass shall not be different from that in the tank. Short gauge glasses are necessary in order to avoid, as far as possible, errors which would otherwise arise owing to any difference in the specific gravity of the liquid at varying heights below the liquid-level.

Similarly, when dipping tubes are employed, these should be drilled with a series of holes throughout their length in order to avoid errors through specific gravity changes.

Measurement of Water.

Having taken the measurements necessary for the calculation of the total volume of liquid in the tank, it is necessary to determine the quantity of water, if any, which may be present. For liquids of specific gravity less than 1·0, this is performed in the following manner:

A water-finding rule, or similar instrument, is smeared with a special preparation, partially soluble in water and practically insoluble in petroleum products. The instrument is then lowered to the bottom of the tank, by means of a cord or tape, and after allowing time for the action of water on the preparation, the water-finding instrument is withdrawn. The depth of water is recorded by a change in the colour of the water-finding paste.

Specially prepared paper may also be employed for the measurement of water, the action of such papers being usually slower than that of paste. Paper is, however, still preferred by some gaugers, particularly for the measurement of water in viscous liquids.

When the density of the product is not greatly different from that of water, or when for other reasons water does not separate readily from the liquid to be measured, the methods previously described cannot be employed and special methods must be devised depending on the circumstances.

Should the density of the product be considerably higher than that of water, separation of water, if any, will naturally be on the surface of the liquid, the measuring operation being modified accordingly. When storage tanks are provided with gauge glasses, the above-mentioned procedure may not be necessary if the tank is provided with a gauge glass arranged specially for the measurement of water.

Measurement of Temperature.

Considerable care must be exercised in the measurement of the temperature of large volumes of liquid contained in storage tanks, should reasonable accuracy be desired. It should here be noted that accuracy in the measurement of temperature is at least as desirable as is accuracy in any other part of the measuring operation.

When the temperature of the liquid does not differ greatly from that of the surrounding atmosphere, it is customary to employ a dip can of the type shown in Fig. 10. The cork is inserted in the can, which is then lowered into the liquid. When the desired depth below the liquid surface has been reached, the cord is sharply jerked, removing the cork and allowing the liquid to fill the can. The sample thus obtained is then withdrawn from the tank and a thermometer is rapidly inserted into the dip can. The liquid is stirred with a thermometer and the temperature noted. Temperatures should be taken at various depths, the number of temperatures required depending on the total height of liquid and upon other circumstances.

When the contents of storage tanks are heated, dip cans in which a thermometer is mounted are occasionally employed. A sample is drawn at the desired depth, as already described, but the can is allowed to remain in the tank long enough for the thermometer to attain the temperature of the oil.

Where several such cans are available, they may conveniently be lowered into the tank at various depths before commencing the gauging or ullaging operations, provided this procedure would not disturb the surface of the liquid. After the required period has elapsed the cans full of oil and bearing thermometers are withdrawn from the tank, the temperatures being immediately noted.

Example of the Measurements taken when Gauging the Quantity of Oil discharged from a Tank Steamer to Shore Tanks.

The following is an example of the procedure usually adopted when gauging the quantity of liquid discharged from an oil tanker to shore tanks. Firstly, the temperature and ullage, or dip, of each ship's tank is noted. The tanks are tested for the presence of water and samples are drawn from each compartment. When desired, each of these samples may be retained; alternatively, the number of samples may usually be reduced by the preparation of average composite samples.

The shore tanks are next gauged for oil and water and temperatures and samples are taken at various levels in the liquid, the number of such temperatures and samples depending on the quantity and nature of the liquid in the tank. The pipelines are examined and it is noted whether they are full or empty. When measuring both ship and shore tanks, it is naturally essential that the measurements, whether ullages, dips, or gauge-glass readings, should be taken at the points which have been employed as a basis for the relevant calibration tables. Should there be any doubt as to the position of reference-points when ullaging, or regarding the number of dips or readings which should be taken, if possible the calibration tables should be examined before commencing measurement. Times for the start and finish of each operation are taken.

The cargo can now be transferred from the ship to the shore tanks and pumping is continued until the transfer is complete. The ship's tanks are then examined, and if not completely empty are dipped or ullaged for oil and water, the condition or measurement being noted for each tank.

Some hours must elapse before the shore tanks can be gauged again, as it is necessary for the surface of the liquid to be quite motionless. When the oil is quite steady the tank is gauged for oil and water and temperatures and samples are again taken. The condition of the pipelines is again noted.

Calculation of Weight or Volume

From the data thus obtained it is possible to calculate the volume of oil contained in the shore tanks before and after discharge of the cargo. When desired these volumes can be converted into volumes at any desired standard temperature by the use of suitable coefficients of expansion. If it is necessary to determine the weight of the cargo, the specific gravities or densities of the liquids at the temperatures of measurement must be ascertained. For this purpose the following specific gravity correction factors per degree Fahrenheit, as standardized by the I.P.T., will be found convenient:

Products lighter than kerosene: below 0·740	0·00048
above 0·740	0·00044
White spirit	0·00042
Kerosine	0·00040
Gas oils	0·00036
Diesel engine fuels	0·00035
Lubricating oils	0·00034
Heavy fuel oils	0·00034
Melted asphaltic bitumen, &c.	0·00030

In Great Britain it is customary to determine the specific gravity of petroleum products on the basis $T°/60°$ F. It is common commercial practice to assume that such specific gravities equal one-tenth of the number of pounds per Imperial gallon of liquid at temperature $T°$, and while this assumption is not strictly accurate, it has been adopted in the example quoted later.

In order to illustrate the methods employed for the calculations of oil quantities, the foregoing example is continued, the measurements taken by the gauger and the subsequent calculations being shown in detail. It will, in general, be noted that the function of the gauger is usually to enter into his note-book all the measurements necessary for the calculations which will subsequently be made, the determination of specific gravity where necessary being preferably performed in the laboratory, specific gravities at the temperatures of tank measurements being determined either directly or by subsequent calculation as mentioned in the foregoing section.

Ship........ *Date*........ *Company*........ *Place of discharge*..........
Description of cargo.............

Tank No.	*Ullages* *Oil*	*Ullages* *Water*	*Temperature* ° *F.*
1 Port	22 ft. 10·4 in.	2 9 in.	64
1 Starboard	23 ft. 2 8 in.	2·8 in.	,,
2 Port	6 ft. 6·3 in.	nil	65
2 Starboard	5 ft. 7·1 in.	,,	,,
3 Port	5 ft. 5·7 in.	,,	66
3 Starboard	5 ft. 3·6 in.	,,	,,
4 Port	5 ft. 1·6 in.	0·3 in.	66½
4 Starboard	4 ft. 1·9 in.	nil	,,
5 Port	18 ft. 2·7 in.	,,	67
5 Starboard	18 ft. 6·5 in.	,,	,,
6 Port	26 ft. 6·1 in.	,,	64
6 Starboard	26 ft. 9·3 in.	,,	,,

Berthed.................... *Time*........... *Date*...........
Commenced............... *Time*........... *Date*...........
Finished spirit............ *Time*........... *Date*...........
Finished water........... *Time*........... *Date*...........
Draft: 17 ft. 0 in. Fore
12 ft. 6 in. Aft.

After discharge all tanks were found to be drained and empty.

Shore tank No. 1, before discharge

Position of dip	*Oil dip*	*Water dip*	*Temperature* ° *F.*
North . .	1 ft. 6·8 in.	1 ft. 2·5 in.	62
South . .	1 ft. 7·9 in.	1 ft. 3·6 in.	,,
East . . .	1 ft. 10·1 in.	1 ft. 5·8 in.	,,
West . .	1 ft. 7·5 in.	1 ft. 3·2 in.	,,
Centre . .	1 ft. 0·6 in.	0 ft. 8·3 in.	,,

Specific gravity 0·74472 at 62° F.

Shore tank No. 3, before discharge

Position of dip	*Oil dip*	*Water dip*	*Temperature* ° *F.*
North . .	2 ft. 4·3 in.	0 ft. 7·8 in.	62
South . .	2 ft. 6·8 in.	0 ft. 10·3 in.	,,
East . . .	2 ft. 7·1 in.	0 ft. 10·6 in.	,,
West . .	2 ft. 4·4 in.	0 ft. 7·9 in.	,,
Centre . .	2 ft. 3·8 in.	0 ft. 7·3 in.	,,

Specific gravity 0·74092 at 62° F.

Shore tank No. 1, after discharge

Position of dip	*Oil dip*	*Water dip*	*Temperature* ° *F.*
North . .	16 ft. 3·9 in.	1 ft. 3·0 in.	64
South . .	16 ft. 5·4 in.	1 ft. 4·5 in.	,,
East . . .	16 ft. 7·3 in.	1 ft. 6·4 in.	,,
West . .	16 ft. 4·6 in.	1 ft. 3·7 in.	,,
Centre . .	15 ft. 9·8 in.	0 ft. 8·9 in.	,,

Specific gravity 0·75034 at 64° F.

Shore tank No. 3, after discharge

Position of dip	*Oil dip*	*Water dip*	*Temperature* ° *F.*
North . .	22 ft. 10·2 in.	1 ft. 8·8 in.	63½
South . .	23 ft. 0·5 in.	1 ft. 11·1 in.	,,
East . .	23 ft. 0·8 in.	1 ft. 11·4 in.	,,
West . .	22 ft. 10·1 in.	1 ft. 8·7 in.	,,
Centre . .	22 ft. 10·0 in.	1 ft. 8·6 in.	,,

Specific gravity 0·74969 at 63½° F.
Pipelines empty of spirit before and after discharge.

In the example given the shore tanks were provided with four gauge hatches equally spaced near the rim of the tank and a further dip hatch at the centre. The method usually adopted for the calculation of the average depth of oil is first to determine the average of the outside dips, this result then being averaged with the centre dip. The same procedure is usually adopted when tanks are fitted with a centre gauge hatch and also with two or more equally spaced gauge hatches near the shell of the tank. As previously mentioned, however, tanks of large diameter are occasionally equipped with nine gauge hatches, the usual method of calculation then being to average the four outside measurements, adding the result to the remaining five, the sum being then divided by six in order to ascertain the average depth.

Shore tanks can, in general, be calibrated more accurately than ships' tanks, and it is customary to base calculations of the cargo loaded into or discharged from tank vessels, on the shore-tank measurements, the calculations being given below.

Tank No. 1

	Before discharge *Oil*	*Before discharge* *Water*	*Temp.* ° *F.*	*After discharge* *Oil*	*After discharge* *Water*	*Temp.* ° *F.*
	ft. in.	ft. in.		ft. in.	ft. in.	
N.	1 6·8	1 2·5	62	16 3·9	1 3·0	64
S.	1 7 9	1 3·6	,,	16 5·4	1 4·5	,,
E.	1 10·1	1 5·8	,,	16 7·3	1 6·4	,,
W.	1 7·5	1 3·2	,,	16 4·6	1 3·7	,,
	4)6 8·3	4)5 3 1	,,	4)65 9·2	4)5 5·6	,,
	1 8·075	1 3·775	,,	16 5·3	1 4·4	,,
C.	1 0·6	0 8·3	,,	15 9·8	0 8·9	,,
	2)2 8·675	2)2 0·075	,,	2)32 3·1	2)2 1·3	,,
	1 4·337	1 0·037	,,	16 1·55	1 0·65	,,

Before:

1 ft. 4·0 in.	54,922·81 gal.	1 ft. 0·0 in.	41,177·30 gal.
0 ft. 0·337 in.	1,158·06 ,,	0 ft. 0·037 in.	127·15 ,,
1 ft. 4·337 in.	56,080·87 ,,	1 ft. 0·037 in.	41,304·45 ,,
Water	41,304·45 ,,		
	14,776·42 gal. at 62° F.		
	7·4472		
	110,043·0 lb.		

After:

16 ft. 1·0 in.	663,434·14 gal.	1 ft. 0·0 in.	41,177·30 gal.
0 ft. 0·55 in.	1,892·18 ,,	0 ft. 0·65 in.	2,233·65 ,,
16 ft. 1·55 in.	665,326·32 ,,	1 ft. 0·65 in.	43,410·95 ,,
Water	43,410·95 ,,		
	621,915·37 gal. at 64° F.		
	7·5034		
	4,666,479·8 lb. = 620,460·0 gal. at 60° F.		
Before	110,043·0 ,, = 14,759·0 ,, ,,		
	4,556,436·8 ,, = 605,701·0 ,, ,,		

In a similar manner tank 3 is worked out and the result obtained is:

6,008,160·4 lb. = 798,793·5 gal. at 60° F.

Therefore the quantity discharged into shore tanks is:

Tank 1 . .	4,556,436·8 lb. =	605,701·0 gal. at 60° F.
Tank 3 . .	6,008,160·4 ,, =	798,793·5 ,, ,,
	10,564,597·2 ,, =	1,404,494·5 ,, ,,

The corresponding final specific gravity is found from

$$\frac{10{,}564{,}597{\cdot}2 \text{ lb.}}{1{,}404{,}494{\cdot}5 \text{ gal. at } 60^\circ \text{ F.}} = 7{\cdot}522 \text{ lb. per gal.}$$

Hence the specific gravity = 0·7522 at 60° F.

The quantity discharged as calculated from the ship's calibration charts should not differ greatly from that found in the shore tanks.

As previously mentioned, for commercial purposes it is customary to employ the quantities calculated from shore-tank measurements. Nevertheless, whenever possible barge or ship's tanks should be measured after loading and prior to discharge of the cargo, even when the vessel is not provided with calibration tables.

Should the cargo be discharged satisfactorily, reference to these measurements would probably not be necessary. Should, however, questions arise regarding contamination of cargo or excessive loss, such measurements may be of great assistance. When vessels are provided with reasonably accurate calibration tables, it is further possible to compare the quantity actually on board the vessel with that calculated from shore measurements at ports of loading and discharge. Similarly, it is important that ship's tanks should be carefully sampled, so that samples are available if required.

THE PRINCIPLES OF PRACTICAL ORIFICE METERING

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THE basic principle of orifice metering consists in measuring the difference of pressure between opposite sides of a suitably designed constriction introduced into a pipeline, and from this 'differential pressure', as it is called, and the known characteristics of the constriction (which usually takes the form of a circular hole in a thin plate, known as the 'orifice' plate) the rate of flow of the fluid in the pipe can be calculated. This constriction is often referred to as the 'primary element'. The differential pressure is measured by means of a simple differential manometer or a recording meter which records the readings of a mercury differential manometer on a chart. This is referred to as the 'secondary element'.

There are several distinct types of constriction which are suitable for the accurate measurement of flow, for instance, the Venturi tube, the flow nozzle, and the orifice plate. In this article we are almost entirely concerned with this last type. There are many variations in detail in this one type which are described below, but in essence they all consist simply of a hole in a thin plate placed across the pipe (usually clamped between flanges), with suitably placed connexions into the pipe up and down stream from the plate by which the differential pressure can be measured.

The characteristics of any particular design of orifice plate is given in terms either of the 'discharge coefficient', C, or of the 'orifice efficiency', $\mathfrak{E}$, which may be considered to be the discharge coefficient corrected to suit the pipe in which the orifice is fitted. The exact meaning of these terms and their application in the equations are given later, but in general terms the discharge coefficient can be regarded as the characteristic of the orifice itself (and not of the combination of orifice and pipe size) which determines the rate of discharge of a fluid for a given pressure difference, and it may be borne in mind that the rate of flow under any given conditions is proportional to the discharge coefficient.

In this article we are chiefly concerned with factors which govern the value of the discharge coefficient and the means of calculating its value from the dimensions of the system and the characteristics of the fluid.

Development of the Orifice as a Basis of Measurement

Measurement by means of orifice meter has been investigated by several workers. J. L. Hodgson [7, 1917] worked with carefully made sharp-edged orifice plates on a very small scale (in pipes of 0·378 to 0·755 in. diameter) using principally water as the test fluid. The range of velocities and orifice sizes was necessarily limited, so that, although the principle of dynamic similarity was used to estimate the effect of change of scale to full-size pipes, this method cannot be considered very accurate. Some very large-scale tests were also made on air at Erith as a basis for the design of air meters for mine ventilation, and these tests gave general confirmation of the predictions from the small scale. Here the velocities and Reynolds numbers were high, but air or gases generally are subject to such large volume changes with temperature and pressure that it is difficult to get good enough accuracy of measurement on a large scale for basic calibration work. Later [4, 1921; 8, 1921] the experimental work was extended to lower values of the Reynolds number by the use of glycerine-water solutions, and the general relation between discharge coefficient and the Reynolds number was determined over a fairly wide range.

J. M. Spitzglass [12, 1922] and R. Witte [14, 1928] and others have made extensive determinations of discharge coefficients under various conditions of flow.

Hodgson [9, 1925; 10, 1929] gave the correction which should be applied to the liquid flow equations to allow for the compressibility of gases in passing through the orifice when the differential pressure is an appreciable fraction of the total pressure. Buckingham [5, 1932] gives some experimental data for the same purpose, but a simpler method was shown by Bean, Buckingham, and Murphy [2, 1929] to be accurate enough for most practical purposes.

The V.D.I. [17, 1930] gave recommendations for the design of standard orifice and nozzle plates with figures for the discharge coefficient for each, together with limits for Reynolds number above which they apply with good accuracy. These limits are so high as to be quite impracticable in many cases. The recommended values for the discharge coefficient are given as dependent on the actual pipe diameter which is now a matter of considerable doubt.

There has recently been a great deal more attention paid to the behaviour of fluid in the orifice at much lower velocities, even down to Reynolds numbers in the orifice as low as 10, where the flow is completely stream-line even behind a sharp edge of an orifice plate. Among others F. C. Johansen and H. G. Giese have made systematic measurements in this region, correlating their results on the basis of the Reynolds number.

Giese [6, 1933] worked with a variety of types of orifice which gave very different characteristics with change of shape of the profile at the orifice itself, and in particular he investigated the shape previously suggested by E. Schmit (Fig. 6, G) consisting of a moderately thin plate with rounded edges. He showed that a suitable modification of the edge can prevent most of the rise in the discharge coefficient as the Reynolds number is reduced.

Johansen [11, 1929] worked with sharp-edged orifices only. He not only determined the discharge coefficients, but also examined the type of eddy formation behind the orifice. His results were more particularly concerned with low Reynolds numbers, but they indicated that the discharge coefficient reached a constant value above a certain Reynolds number, a result which is now subject to considerable doubt.

G. L. Tuve and R. E. Sprenkle [13, 1933] also worked in this region of low Reynolds number (40–40,000) and have given an excellent correlation of their own and other workers' results in the form of a chart giving the discharge coefficient against the Reynolds number for each value of the diameter ratio. This refers to the ratio

$$\frac{\text{Diameter of the orifice}}{\text{Diameter of the pipe}}$$

and is abbreviated d/D. This chart has been taken as the

basis of Fig. 5 in this report and will be referred to later. Their chief conclusion is that over the range of conditions investigated, all experimental results can be correlated on this basis within $\pm 1\frac{1}{2}\%$ without introducing the absolute size of the pipe at all.

The limitation to their work lies in the fact that the range of Reynolds number covered does not extend much above 40,000 in the orifice, and for a complete scheme, which will cover the metering of all fluids including gases, Reynolds numbers up to about 2,000,000 must be included.

This region has been lately investigated by S. R. Beitler [3, 1933] who used water throughout for these tests, and worked up to Reynolds numbers of 10,000,000 and over. He found that the discharge coefficient does not depend on the absolute diameter, but only on the Reynolds number and the diameter ratio for a given type of orifice, and, a new feature, that the discharge coefficient for a given value of d/D does not become constant at any value of the Reynolds number however high, but changes continuously (but, of course, at a decreasing rate) up to the highest values investigated.

This is an important conclusion, since it implies that there is no 'limiting value' which can be assigned to the discharge coefficient for each diameter ratio as had always previously been assumed. This means to say that the value which is to be assigned to the discharge coefficient must take into account the Reynolds number under the actual conditions of flow.

The A.S.M.E. [15, 1933] have issued a useful summary of the conditions which should be complied with in order to ensure accurate metering. The limiting edge thickness in the case of square-edged orifices has also been investigated by Beitler [3, 1934], and his conclusions are given later (see Fig. 10).

To summarize the present state of knowledge on the value to be assigned to the discharge coefficient for different sizes and conditions of flow, it may be said that the correlation of Tuve and Sprenkle can be taken to be quite satisfactory at medium and low values of Reynolds number, particularly as in this region quite the same accuracy cannot be expected as at higher values. The correlation of data at higher values than, say, 40,000 is not so satisfactory, partly because of scarcity of accurate data, and partly because the earlier investigators appear rather to have assumed that the discharge coefficient reached a limiting value, instead of looking for a general relationship with the Reynolds number.

There remains also a certain amount of doubt as to what effect, if any, the actual diameter of the pipe has on the discharge coefficient. Theoretically some effect is to be expected, since the velocity distribution across the cross-section must be different with pipes of different relative roughness, and it is known from pipe-flow data that small pipes are relatively rougher than large pipes of the same type. However, it appears that in the case of reasonably large steel pipes this effect is not very great, and since different workers who attribute some variation in the coefficient to this cause do not agree as to the extent, it is probably best to follow Tuve and Sprenkle and Beitler, and eliminate this factor altogether.

A proposal is made in this article to choose an arbitrary but convenient nominal value for the discharge coefficient, namely, 0·600, and to arrange that all deviations from this value shall be allowed for in the form of a 'correction factor', M. This is only a very small departure from normal practice, since the true discharge coefficient C is in this case simply $0{\cdot}600M$. The great advantage of this arrangement is that all the basic tables used for routine work on orifice metering can be worked out once and for all; any changes in the coefficients which may be found to be desirable at some later date as a result of further work, or change in the position of pressure taps, &c., can then be easily incorporated in a revised chart and table of this 'correction factor'.

Basic Principles

The measurement of the flow of fluids by orifice, flow nozzle, or Venturi meter depends on the conversion of static head to velocity head, and the principles governing the measurement of flow in this way are given by Bernouilli's theorem, which is the mathematical expression of the general principle of conservation of energy applied to this case, and may be described briefly as follows.

In the absence of friction, if the velocity of a fluid is increased, as, for instance, in passing through an orifice, its kinetic energy, $U^2/2g$, must clearly be increased, and this can only be done at the expense of its potential energy. This potential energy is made up of: the mechanical work of delivering the fluid at the pressure p, denoted by pv, the gravitational potential energy, gH, and any internal energy due, for instance, to the energy of expansion of a gas, denoted by W, say.

In the case of liquids the specific volume is constant, and there is therefore no energy of expansion. If the flow takes place in a horizontal pipe, the gravitational energy is constant, and therefore the last two sources of potential energy may be neglected. The increase in kinetic energy can therefore only be obtained at the expense of a drop in pressure. In such circumstances and assuming isothermal flow, Bernouilli's equation for liquids becomes

$$p_1 v_1 + \frac{U_1^2}{2g} = p_2 v_2 + \frac{U_2^2}{2g}, \tag{1}$$

but since $v_1 = v_2 = 1/\rho$, say, equation (1) can be written

$$U_2^2 - U_1^2 = \frac{2g}{\rho}(p_1 - p_2). \tag{2}$$

In these equations U_1 is the initial velocity of the fluid where the static pressure is p_1, and U_2 is the increased velocity when the static pressure has fallen to p_2. As usual g is the acceleration due to gravity and ρ is the density of the liquid under the conditions of flow.

If the liquid is initially at rest, that is, $U_1 = 0$, the equation reduces to

$$U_2 = \sqrt{\left\{\frac{2g}{\rho}(p_1 - p_2)\right\}}. \tag{3}$$

This condition is very closely fulfilled when the diameter of the orifice is one-fifth of the diameter of the pipe or less. In that case U_1^2 will be less than 0·2% of U_2^2. If the pressure difference $(p_1 - p_2)$ is expressed in terms of head of the liquid flowing in the pipe (ΔH), we can substitute $(p_1 - p_2) = \rho(\Delta H)$ in equation (3) and we get

$$U_2 = \sqrt{\{2g(\Delta H)\}} \tag{4}$$

or

$$(\Delta H) = \frac{U_2^2}{2g}. \tag{5}$$

The head of liquid (ΔH) is called the 'velocity head' and is that drop in pressure head of the liquid required theoretically to produce the given velocity U_2.

For gases it can be shown that, neglecting differences in

potential heads, Bernouilli's theorem for compressible fluids becomes

$$\frac{U_2^2}{2g}-\frac{U_1^2}{2g}=p_1v_1-p_2v_2+W. \tag{6}$$

For isothermal flow this equation can be simply developed by the substitution of $\int_{v_1}^{v_2} p\,dv$ for W representing the isothermal work of expansion, and further simplified to give

$$(U_2^2-U_1^2)=\frac{2g}{\rho}(p_1-p_2) \tag{7}$$

which is the same as for an incompressible liquid.

The flow through an orifice or nozzle is actually very nearly adiabatic, but the error introduced by the use of the equation for isothermal flow is very small if the value used for the density ρ is that for the mean between the upstream and downstream conditions.

In practical orifice metering it is convenient to calculate the mean velocity of the fluid at the area of the orifice, but the pressure difference across the orifice is measured by means of connexions to the pipe at some position above and below the orifice, and this pressure difference corresponds more nearly to the velocity at the position of minimum cross-section of the stream which is considerably smaller than the cross-section of the orifice itself. Bernouilli's equation, of course, applies only to pressure and velocity measurements at exactly the same points. The departure from this ideal condition is met by the introduction into the theoretical equations of an empirical "discharge coefficient" for the particular orifice arrangement as mentioned above, and in this coefficient is also included any allowance for friction and other incidental effects.

General Features of Flow at an Orifice

When any fluid passes from a channel of large cross-section to one of a small cross-section, the mean velocity of the fluid must increase and, as explained above, a pressure difference must exist in order to cause this acceleration. Another obvious result of such a reduction of cross-section is that the fluid which was flowing along near the wall of the larger section must flow inwards to clear the obstruction, and in doing so acquires a radial component to the velocity. Owing to the inertia of the fluid this radial velocity causes the steam to contract in the form of a jet to a smaller cross-section than that of the obstruction at a point slightly downstream from the plane of the orifice. Below this the cross-section of the stream increases again until it fills the pipe. This is illustrated in Fig. 1, A, B, C, D, in which the general direction of flow is from left to right.

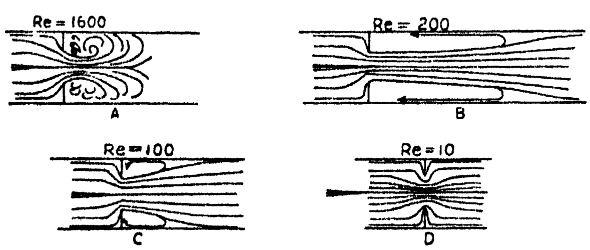


FIG. 1.

If the fluid in question is a liquid, and a gas were to be admitted behind the orifice, there would be an actual surface of separation defining this jet, but in the usual case the space outside the jet is filled with more or less stagnant liquid.

The conditions existing in this region were investigated by Johansen [11, 1929] who found that at Reynolds numbers above 1,600 this region is filled with eddies, whereas below 200 there is no trace of eddies but a slow return flow of liquid in a direction opposite to the main flow. At Reynolds numbers below 100 the effect of viscosity is so great that the stream does not contract below the orifice, but the stagnant region remains. At a Reynolds number of 10 there is no sign of a jet below the orifice and the flow is symmetrical with respect to the orifice plate, the fluid close to the pipe walls being deflected at right angles and adhering closely to the diaphragm on each side. Under these conditions, of course, the flow is purely viscous and the pressure difference must be strictly proportional to the velocity, which is equivalent to the discharge coefficient being proportional to the Reynolds number.

The distribution of pressure along the pipe on each side of the orifice at moderate values of Reynolds number (10,000) are shown in Fig. 2 for various values of diameter ratio.

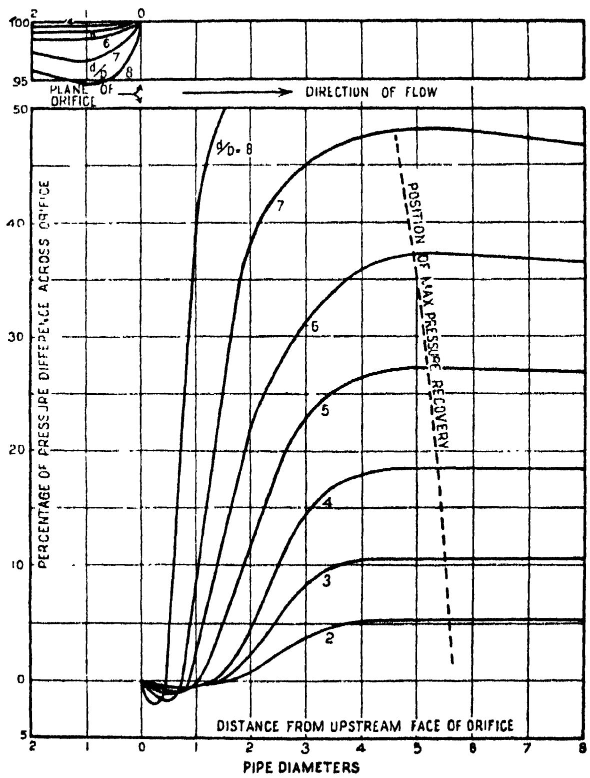


FIG. 2. Pressure distribution near orifice at Reynolds number = 10,000.

It will be noticed that, particularly with the larger diameter ratios, a considerable fraction of the pressure difference at the orifice is recovered at a position about 5 pipe diameters downstream, and there are small but appreciable changes of pressure very close to the orifice plate on both sides. This effect has a bearing on the exact location of the pressure taps for accurate metering.

The point where the cross-section of the jet is a minimum is known as the 'vena contracta', and at this point all the lines of flow are parallel to the axis and therefore, in the absence of friction, all the potential energy due to the pressure difference should theoretically be converted into kinetic energy of forward motion. The velocity should then

be given by equating the velocity head to the differential pressure. By multiplying this 'theoretical velocity' by the area of the vena contracta we should get the rate of volume flow directly.

Derivation of Fundamental Formulae

Supposing that the orifice were placed in a very large pipe, the velocity in the pipe at some distance from the orifice could be neglected, and the 'theoretical velocity' would simply be (working throughout in self-consistent units), as explained above,

$$U_2 = \sqrt{\{2g(\Delta H)\}} \tag{4}$$

where ΔH = the differential pressure in terms of the head of fluid at the orifice,

and g = acceleration due to gravity.

Supposing that we write for the area of the vena contracta $C \times a$,

where C = the coefficient of discharge (or the coefficient of contraction),

and a = area of the orifice,

we should get for the volume rate of flow, q,

$$q = C \times a \times \sqrt{(2g\,\Delta H)}.$$

Now this equation should be corrected to take into account the 'velocity of approach' of the fluid in the pipe which will clearly cause a greater throughput for a given differential pressure than shown by this equation.

The theoretical correction is derived directly from Bernouilli's theorem and consists in dividing C by

$$\sqrt{\left\{1-\left(\frac{a'}{A}\right)^2\right\}},$$

where a' is the area of the vena contracta and A is the area of the pipe. The use of this theoretical correction is inconvenient in practice since a' cannot be obtained by measurement, and it has therefore become customary to use the area of the orifice in place of that of the vena contracta in the above expression.

Instead of applying this correction to the theoretical velocity it is customary to apply it to the coefficient of discharge C, and the fundamental formula connecting the pressure drop across an orifice and the volume flowing through it then becomes

$$q = \frac{C}{\sqrt{\left\{1-\left(\frac{a}{A}\right)^2\right\}}} \times a \times \sqrt{(2g\,\Delta H)}, \tag{8}$$

or if the orifice and main pipeline are circular

$$q = \frac{C}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}} \times \frac{\pi d^2}{4} \times \sqrt{(2g\,\Delta H)}, \tag{9}$$

where q = volume rate of flow through the orifice,
C = discharge coefficient,
a, A = area of orifice and pipe respectively,
d, D = diameter of orifice and pipe respectively,
ΔH = differential head of fluid at the orifice,
g = acceleration due to gravity.

The first term in these equations is usually called the *orifice efficiency*, and it may be described as the discharge coefficient corrected for the velocity of approach in the main pipeline. In this article we shall denote the orifice efficiency by the letter $\mathbf{E}$, and it is therefore defined thus:

$$\mathbf{E} = \frac{C}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}}. \tag{10}$$

According to the proposal mentioned above, instead of the true discharge coefficient C we will use $0{\cdot}600 \times M$, where M is a correction factor determined by experiment (see Fig. 5) and represents the departure of the true value of the discharge coefficient C from the nominal value 0·600. Equation (10) then becomes

$$\mathbf{E} = \frac{0{\cdot}600M}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}},$$

and equation (9) can then be written

$$q = \left[\pi\sqrt{\frac{g}{8}}\,\frac{0{\cdot}600}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}} \times d^2\right] M \times \sqrt{(\Delta H)}. \tag{11}$$

The expression in the square brackets contains nothing but the diameters of the pipe and orifice and constant terms. It can therefore be evaluated by straightforward arithmetical computation as it does not depend at all on experiment.

Equations for Practical Use

Equation (11) applies to self-consistent units, but in practice these are inconvenient since q is usually required in such units as gallons per hour, barrels per day, &c., and the differential head ΔH is usually measured in inches. The result of using these practical units is to alter the constant term $\pi\sqrt{(\frac{1}{8}g)}$ in the square brackets. Furthermore, the differential pressure is not measured in head of the fluid flowing in the pipe, but usually in terms of head of water at 60° F., and the volume rate of flow q must be reduced to standard conditions, e.g. 60° F. in the case of liquids. This can readily be shown to introduce a factor into the right-hand side of the equation equal to

$$\sqrt{\frac{S_f}{S_{60}}},$$

where S_f = sp. gr. of the fluid under the conditions at the orifice referred to water at 60° F.,

and S_{60} = sp. gr. of the fluid at 60° F. referred to water at 60° F.

There is usually also a small correction to be applied owing to the fact that a differential mercury manometer or a recording meter employing mercury as the manometric liquid is normally used, and the fluid which is being metered is normally present in the U-tube above the mercury. In this case the scale readings given by a manometer calibrated in head of water pressure difference with *water* above the mercury in both limbs must be multiplied by the factor $\left(\frac{13{\cdot}57-S_m}{12{\cdot}57}\right)$ to obtain the true pressure difference in heads of water at 60° F. In this expression S_m is the specific gravity of the fluid over the mercury at the temperature of the meter referred to water at 60° F. Alternatively, if the meter had been calibrated in head of water with *air* above the mercury in both limbs, the factor would be $\left(\frac{13{\cdot}57-S_m}{13{\cdot}57}\right)$. If, therefore, the scale reading in nominal head of water is used in equation (11), the right-hand side must be multiplied by the square root of one or other of these factors. Similar factors to these apply to cases where liquid seals are used between the orifice and the meter. If these factors are introduced into equation (11) and a typical set of practical

units are used instead of self-consistent units, we get, for example, for liquids:

$$q_{60} = \left[283{\cdot}3 \times \frac{0{\cdot}600}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}} \times d^2\right] \times$$

$$\times \sqrt{\left\{\frac{(13{\cdot}57-S_m)S_f}{12{\cdot}37(S_{60})^2}\right\}} \times M\sqrt{h}, \quad (12)$$

where q_{60} = rate of volume flow reduced to 60° F. (imp. gal. per hr.),

d, D = diameter of orifice and pipe respectively (in.),

h = pressure difference in nominal inches of water, as given by a mercury differential manometer calibrated with *water* above the mercury at 60° F.

If these particular units are decided on, a set of tables can be prepared giving the values of the factor in the square brackets for all values of the diameter ratio (d/D) and all the normal pipe sizes. A single table calculated for a pipe diameter of 1·0000 is given below, from which tables for other pipe sizes and other sets of units can be calculated by simple multiplication. Owing to the absence in this expression of any experimental data these tables can be calculated once and for all.

TABLE I

Values of E, Ed^2, and 283·3Ed^2 calculated for D = 1·000

Based on $E = 0{\cdot}600\Big/\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}$

d/D	E	Ed^2	$283{\cdot}3Ed^2$
0·1	0·6000$_5$	0·0060005	1·700
0·11	0·6000$_5$	0·0072606	2·057
0·12	0·6000$_5$	0·0086407	2·448
0·13	0·6001	0·0101417	2·873
0·14	0·6001	0·0117620	3·332
0·15	0·6001$_5$	0·0135034	3·826
0·16	0·6002	0·0153651	4·353
0·17	0·6002$_5$	0·0173472	4·914
0·18	0·6003	0·0194497	5·510
0·19	0·6004	0·0216744	6·140
0·20	0·6005	0·0240200	6·805
0·21	0·6006	0·0264865	7·504
0·22	0·6007	0·0290739	8·237
0·23	0·6008$_5$	0·0317850	9·005
0·24	0·6010	0·0346176	9·807
0·25	0·6011$_5$	0·0375719	10·644
0·26	0·6013$_5$	0·0406513	11·516
0·27	0·6016	0·0438566	12·424
0·28	0·6018$_5$	0·0471850	13·367
0·29	0·6021	0·0506366	14·345
0·30	0·6024$_5$	0·0542205	15·360
0·31	0·6028	0·0579291	16·411
0·32	0·6031$_5$	0·0617626	17·498
0·33	0·6036	0·0656320	18·594
0·34	0·6040$_5$	0·0698282	19·781
0·35	0·6045$_5$	0·0740574	20·980
0·36	0·6051	0·0784210	22·217
0·37	0·6057	0·0829203	23·491
0·38	0·6063$_5$	0·0875569	24·805
0·39	0·6070$_5$	0·0923323	26·158
0·40	0·6078$_5$	0·0972560	27·553
0·41	0·6086$_5$	0·1023140	28·986
0·42	0·6095$_5$	0·1075216	30·462
0·43	0·6105$_5$	0·1128906	31·982
0·44	0·6116	0·1184057	33·546
0·45	0·6127	0·124070	35·15
0·46	0·6138$_5$	0·129891	36·80
0·47	0·6152	0·135898	38·50
0·48	0·6166	0·142065	40·25
0·49	0·6181	0·148406	42·04
0·50	0·6197	0·154925	43·89
0·51	0·6214	0·161626	45·79
0·52	0·6232$_5$	0·168527	47·74
0·53	0·6252	0·175619	49·75
0·54	0·6272$_5$	0·182906	51·82
0·55	0·6295	0·190424	53·95
0·56	0·6319	0·198164	56·14
0 57	0·6344	0·206117	58·39
0·58	0·6371	0·214320	60·72
0·59	0·6400	0·222784	63·11
0·60	0·6431	0·231516	65·59
0·61	0·6464	0·240525	68·14
0·62	0·6499$_5$	0·249841	70·78
0·63	0·6537	0·259454	73·50
0·64	0·6577	0·269394	76·32
0·65	0·6620	0·279695	79·24
0·66	0·6665$_5$	0·290349	82·26
0·67	0·6714$_5$	0·301414	85·39
0·68	0·6767	0·312906	88·65
0·69	0·6823	0·324843	92·03
0·70	0·6883	0 337267	95·55
0·71	0·6947$_5$	0·350223	99·22
0·72	0·7016$_5$	0·363735	103·00
0·73	0·7090$_5$	0·377853	107·00
0·74	0·7170$_5$	0·392657	112·00
0·75	0·7257	0·408206	115·60
0·76	0·7350	0·424536	120·30
0·77	0·7451	0·441770	125·20
0·78	0·7560	0·459950	130·30
0·79	0·7679	0·479246	135·80
0·80	0·7809	0·499776	141·60

Similarly, the factor under the square root sign can be tabulated by simple computation and it can be converted to the corresponding factor applicable to meters calibrated with *air* above the mercury by multiplying by 0·9625. The most convenient form of tabulation of this factor for routine use is to divide it into two factors and tabulate each of them separately, thus:

$$\sqrt{\left\{\frac{(13{\cdot}57-S_m)S_f}{12{\cdot}57(S_{60})^2}\right\}} = \sqrt{\left\{\frac{(13{\cdot}57-S_m)}{12{\cdot}57\,S_{60}}\right\}} \times \sqrt{\frac{S_f}{S_{60}}}.$$

Some values for the constant which should be used in place of 283·3 in equation (12) when the flow measured in other units given by the Foxboro Instrument Company are as follows:

Time	*Cu. ft.*	*Imp. gal.*	*U.S. gal.*	*Barrels*
Second .	0·01215	0·07568	0·09089	0·002164
Minute .	0·7290	4·541	5·453	0·1298
Hour .	43·74	272·4	327·2	7·790
24-hr. day	1,050	6,540	7,853	187

These values apply to meters calibrated with *air* above the mercury in inches of water at 60° F. and should be divided by 0·9625 to get the correct values for meters calibrated with *water* above the mercury.

For experimental work on the small scale it is often required to measure the flow in cubic centimetres per second and the differential pressure in centimetres of water. The constants for these units are 215·9 and 224·3 for

mercury manometers calibrated with air and water above the mercury respectively.

Equations for Gases

Equation (11) is of general application to any fluid. Equations of the same type as (12) could also be used for gases, but the evaluation of S_f would be inconvenient. For use with gases we can obtain a more convenient equation by substituting for q and ΔH in equation (11) as follows:

$$q = \frac{\rho_s}{\rho_f} \times q_s$$

$$\Delta H = h_w \times \frac{\rho_w}{\rho_f},$$

where q_s = volume flow of gas at S.T.P. (cu. ft. per hr.),
ρ_s = density of gas at S.T.P. (lb. per cu. ft.),
ρ_f = density of gas at orifice conditions (lb. per cu. ft.) (see later),
ρ_w = density of water at 60° F.,
h_w = head of water at 60° F. (lb. per cu. ft.).

We then get

$$q_s = \left[\pi\sqrt{\frac{g}{8}}\,\frac{0{\cdot}600}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}}\times d^2\right]\times\frac{\rho_f}{\rho_s}\sqrt{\frac{\rho_w}{\rho_f}}\times M\sqrt{h_w}$$

$$= \left[\pi\sqrt{\frac{g}{8}}\,\frac{0{\cdot}600}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}}\times d^2\right]\times\sqrt{\frac{\rho_w}{\rho_a}}\sqrt{\frac{\rho_f}{\rho_s G}}\times M\sqrt{h_w}, \quad (13)$$

where G = specific gravity of gas rel. air,
ρ_a = density of air at S.T.P. (lb. per cu. ft.).

It is now necessary to express $\sqrt{(\rho_f/\rho_s G)}$ in terms of the pressure and temperature at the orifice, the specific gravity of the gas (rel. air), and the deviation of the gas from the gas laws at orifice conditions.

If V_s is the specific volume of the gas at S.T.P., then the calculated specific volume at T_f, P_f, *assuming the gas laws to hold*, is

$$V_s \times \frac{T_f P_s}{T_s P_f}.$$

Let δ be the factor by which this *calculated* specific volume must be multiplied to get the *true* specific volume at $T_f P_f$. Denoting the latter by V_f, we may write

$$V_f = \delta \times V_s \times \frac{T_f P_s}{T_s P_f}.$$

δ is called the deviation, and values may be obtained for hydrocarbon gases from Fig. 3.

Now $$\frac{\rho_f}{\rho_s} = \frac{V_s}{V_f} = \frac{1}{\delta} \times \frac{T_s P_f}{T_f P_s}.$$

Hence $$\sqrt{\frac{\rho_f}{\rho_s G}} = \sqrt{\left(\frac{T_s P_f}{G T_f P_s \delta}\right)}.$$

Making this substitution in equation (13) and at the same time changing the constant so as to apply to one of the usual set of practical units for gas flow, we get

$$q_s = \left[1{,}300 \times \frac{0{\cdot}600}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}}\times d^2\right]\sqrt{\left(\frac{T_s P_f}{G T_f P_s \delta}\right)}\times M\sqrt{h}, \quad (14)$$

where Q_s = volume flow reduced to standard temperature and pressure (cu. ft. per hr.),
T_s, T_f = absolute temperatures (standard temperature and flowing temperatures respectively),
P_s, P_f = absolute pressures (standard pressure and flowing pressure respectively),
d, D = orifice and pipe diameters (in.),
G = sp. gr. of gas rel. air,
δ = deviation from gas laws (Fig. 3),
$h = h_w$ = pressure difference in nominal inches of water given by meter calibrated with *air* above the mercury.

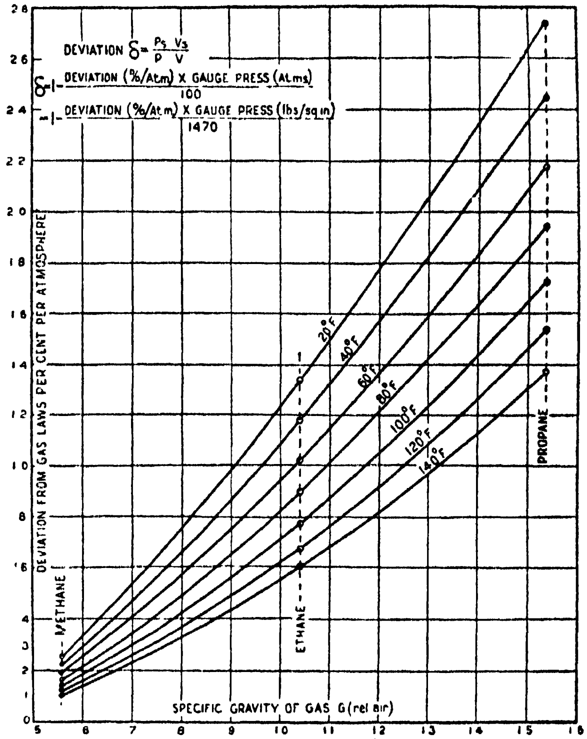


FIG. 3. Deviation of hydrocarbon gases from gas laws.

The constant which should be used in this equation in place of 1,300 for small-scale experimental work, where Q is measured in c.c. per sec. and h in cm. of water, is 1,029.

Equation (14) can be converted for use with other units by a simple change of constant. This equation and equation (12) for liquids can also quite simply be converted to measurement by weight by a change of constant and the multiplication of the right-hand side by the specific gravity of the gas or liquid under standard conditions.

The factor under the square root sign in equation (14) can be put in the form of a chart, or, alternatively, it may be divided into four separate factors which may be tabulated separately for routine use, namely,

$$\sqrt{\left(\frac{T_s P_f}{G T_f P_s \delta}\right)} = \sqrt{\frac{1}{G}} \times \sqrt{\frac{T_s}{T_f}} \times \sqrt{\frac{P_f}{P_s}} \times \sqrt{\frac{1}{\delta}}.$$

In deriving equation (14) from equation (11), ρ_f was taken to be the density of gas under "orifice conditions", and this needs further definition, since the density changes with the pressure. With certain assumptions Hodgson [10, 1929] derived a theoretical expression which applies to the case of adiabatic flow through the orifice, but this is very complicated and in any case finally relies on experimental measurements. Buckingham [5, 1932], as a result of experiments on square-edged orifices, obtained the following empirical relationship for an 'expansion factor' Y to be applied to the true discharge coefficient to allow for the finite value of the pressure drop across the orifice:

$$Y = 1 - \frac{P_1 - P_2}{P_1 \gamma}\left[0{\cdot}41 + 0{\cdot}35\left(\frac{d}{D}\right)^4\right].$$

This has been established for values of d/D lying between 0·2 and 0·87 for flange connexions, and it is said to be correct to within $\frac{1}{2}$% when P_2/P_1 is $< 0{\cdot}8$. Values from this expression do not agree very well with Hodgson's experimental results. However, Bean, Buckingham, and Murphy [2, 1929] state that the use of a mean pressure (i.e. $(P_1+P_2)/2$), for calculating the density of the gas, gives an accuracy within 2% without the added complication of an expansion factor. This entails substituting $(P_1+P_2)/2$ for P_f in equation (14).

Taking, for example, a 60-in. meter operating at full flow with a pressure of 1 atm. downstream, $(P_1-P_2)/P_1$ is roughly 0·13, and the use of the mean pressure as suggested by Bean, Buckingham, and Murphy results in a correction of just over 3% for compressibility. Comparing this with Hodgson's results, the error would be ± 2% depending on the values of d/D and V, while the agreement with Buckingham's empirical formula is somewhat better.

The more accurate equations for the compressibility correction assume that the temperature of the gas is measured upstream, that is, at a point corresponding to P_1. The comparison given above between the use of the mean pressure and the more accurate expressions is based on the use of the upstream temperature in this case also. This is the position at which the temperature is usually measured.

This subject is summarized in the *Chemical Engineers' Handbook* [16, 1934], but since it is not possible in any case to obtain as high an accuracy when metering gases as when metering liquids, it is recommended that for gases the mean pressure should be used to allow for the effect of compressibility. When very high accuracy is required the only safe course to adopt is to arrange for the differential pressure to be so small that the correction for compressibility is negligible.

It may be mentioned that it is very desirable that the static pressure connexion for all meters should be taken either from the upstream or the downstream side of the orifice so as to avoid the possibility of error in arriving at the mean pressure. Thus, if the static pressure is measured at the upstream side, then half the differential pressure must be subtracted from the static pressure reading on the chart, while if it is measured on the downstream side, half the differential pressure must be added.

Variation of Discharge Coefficient with Reynolds Number

It has already been pointed out that the character of the flow changes with increase of Reynolds number. The effect of this change on the value of C has long been recognized, and formed part of Hodgson's original investigation. The number of experiments done by him and by others until quite recently was small, and the object of the investigators was to show that above a certain value of R_e the value of C becomes constant, or at least was sufficiently nearly constant for it to be taken as such for practical purposes. It was often recommended that orifice meters should not be used at values of R_e less than that which marked the beginning of the region where C was constant, and these recommendations were adhered to when possible. However, it was frequently impossible to obtain the necessary value of the Reynolds number owing to the differential pressure exceeding the maximum meter head, and in such cases an error of unknown magnitude was introduced into the meter constant. It was obvious from the work of Hodgson and others that in very unfavourable cases the error might become as high as 70%, but no attempt was made to correlate the available data so that the error could be estimated and allowance made for it.

Recently, however, the value of C in this region has been thoroughly investigated by Tuve and Sprenkle [13, 1933], who have carried out extensive experiments with water over a range of 100–40,000, using corner taps. They have cor-

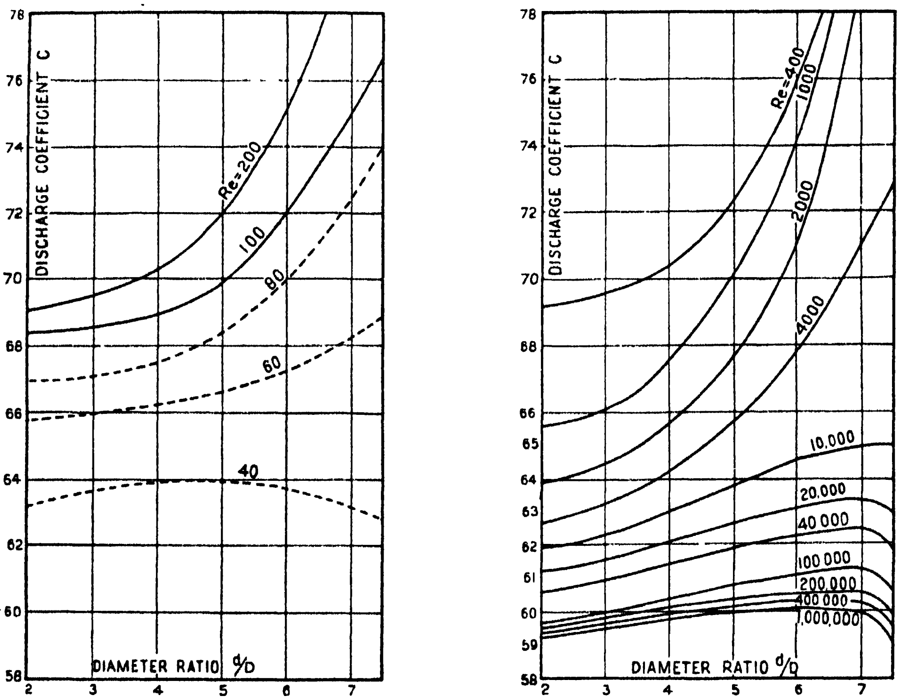


FIG. 4. Discharge coefficient—d/D for various values of R_e.

related their results and compared them with those of other workers.

Beitler [3, 1933] has carried out extensive tests at higher Reynolds numbers up to 50,000,000, which indicate that C does not become constant at high Reynolds numbers, but continues to diminish slightly in value.

The V.D.I. give values of C for corner taps at higher values of R_e (up to 160,000) which are founded on the experimental results of Witte [14, 1928].

The data from these sources for sharp-edged orifices and corner taps was correlated in the following way. Values of

Reynolds number for the particular set of conditions and read the corresponding value of M from Fig. 5.

For routine work it is usually preferable to have the necessary data in the form of a table rather than a chart, and this has been provided for the most usual range of Reynolds numbers in Table II. Unfortunately this process of tabulation is bound to introduce certain errors of approximation unless the table is made unduly large. However, since the accuracy of the fundamental data cannot claim to be very exact at the present stage it is thought that the table could be used without appreciable disadvantage in practice.

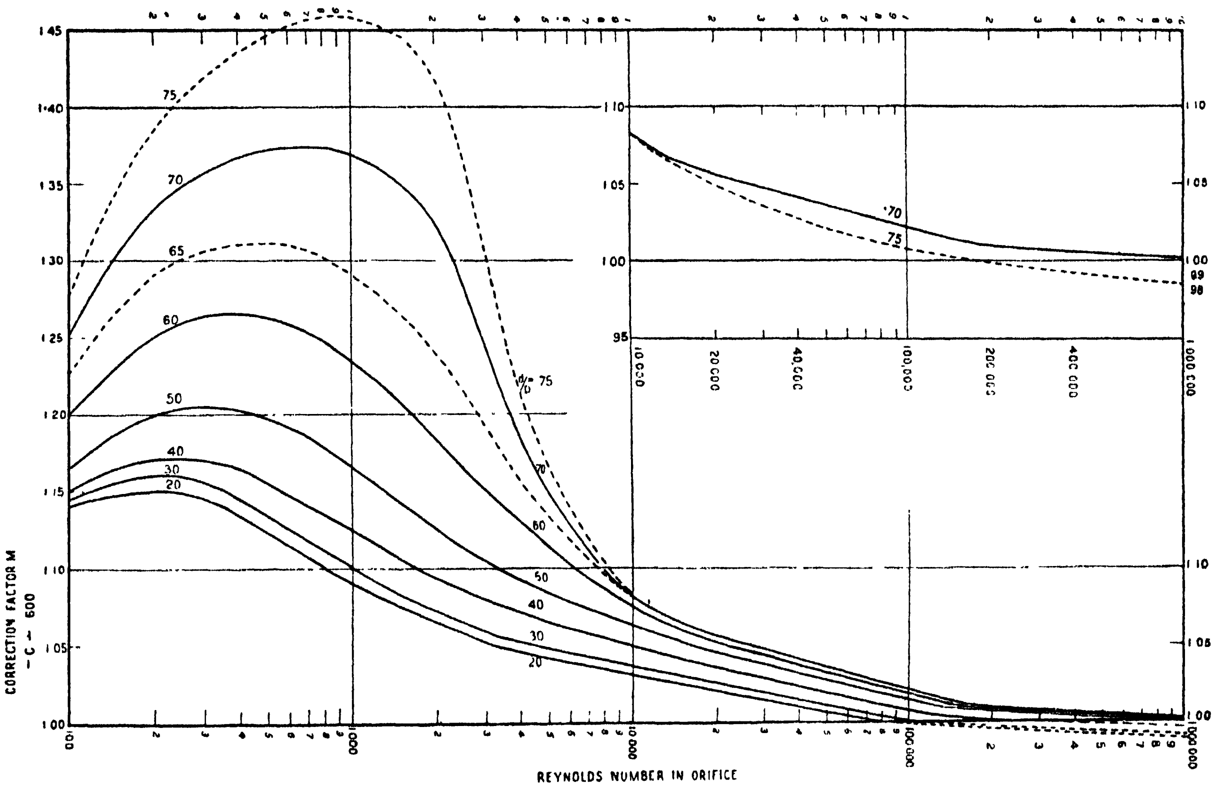


FIG. 5. Correction factor M – Reynolds number in orifice.

C were plotted against R_e, for various values of d/D, a few typical curves being shown later on Fig. 7. These lines were then extrapolated to higher values of R_e so that C decreased in accordance with Beitler's results. The graph so obtained was then used to plot C against d/D for various values of R_e, as shown in Fig. 4.

In certain places it was found that these curves were not smooth, and when this was found to be the case, the point was adjusted to conform with the others and the corresponding point on the curves of Fig. 7 adjusted accordingly. The points on the final curves were in this way altered as little as possible from the original plotting.

Finally Fig. 5 was obtained by dividing the values of C by 0·600 to give the correction factor M. It should be noted that this correlation was worked out before the full details of Beitler's work were published, but these would only be likely to influence the values at very high values of R_e. See article 'Measurement of Gas' by E. S. L. Beale.

If these curves are then to be taken as the best representation of the variation of the discharge coefficient from the nominal value of 0·600, when calculating an orifice, the best method would therefore be to work out the

Table II has been drawn up from Fig. 5 to cover the range of Reynolds numbers above 10,000. At lower Reynolds numbers than this the variation of M is so great that an unduly large table would be needed to cover this region with steps of $\frac{1}{2}$% (or even 1%) in the value of M.

It will be noted that the value of M takes no account of the size of the pipe. It has been pointed out above that roughness, and hence change of pipe size, which alters relative roughness, will probably have some effect on the value of C. Evidence as to the magnitude of this effect is meagre and conflicting, but it would appear small enough to be neglected without important loss of accuracy.

Types of Orifice Plate

There are several designs of orifice plate which are in use for various purposes. Some of these are merely alternative forms intended for the same purpose, while others are special designs adapted to suit some particular circumstance. As some of the latter may be found useful in special cases, and as it is necessary to distinguish clearly between the former (particularly as it is sometimes not quite clearly stated which arrangement is referred to), the most

important variations are given below and the main features of each are briefly discussed.

There are three independent features by which the different types of orifice are distinguished, namely:

1. The cross-section of the orifice.
2. The shape of the edge of the orifice.
3. The arrangement of the pressure connexions.

2. Type of Edge.

The type of orifice in common use is generally referred to as 'sharp-edged', but there are actually three types of construction for the edge known as *Sharp Edge* (Fig. 6, D) and *Square Edge* (Fig. 6, E), and there is the further variant known as the *Bevelled Edge* (Fig. 6, F) which is used in the case of thick orifice plates.

TABLE II

Correction Factor $M = \frac{C}{0{\cdot}600}$ *for Sharp-edged Orifices and Corner Taps*

Multiply Number in Table by 1,000 for Reynolds Number in Orifice

M \ d/D	*Up to 0·20*	*Over 0·20 to 0·30*	*Over 0·30 to 0·35*	*Over 0·35 to 0·40*	*Over 0·40 to 0·45*	*Over 0·45 to 0·50*	*Over 0·50 to 0·55*	*Over 0·55 to 0·60*	*Over 0·60 to 0·70*	*Over 0·70 to 0·725*	*Over 0·725 to 0·75*
0·985	over 1,000	over 1,000	..	..	..	..	..	..	..	..	over 1,000
0·990	490–1,000	600–1,000	over 1,000	over 1,000	..	..	..	..	..	over 2,000	550–1,000
0·995	120–440	160–600	260–1,000	450–1,000	over 1,000	over 1,000	over 1,000	over 2,000	over 2,000	800–2,000	300–550
1·000	63–120	76–160	95–260	150–450	250–1,000	400–1,000	600–2,000	600–2,000	700–2,000	400–800	180–300
1·005	44–63	55–76	70–95	92–150	110–250	140–400	200–600	200–600	250–700	170–400	130–180
1·010	33–44	40–55	51–70	68–92	82–110	100–140	120–200	130–200	150–250	130–170	90–130
1·015	23–33	30–40	38–51	50–68	62–82	77–100	90–120	95–130	115–150	100–130	69–90
1·020	17–23	21–30	28–38	37–50	46–62	59–77	68–90	76–95	90–115	80–100	56–69
1·025	12–17	15–21	21–28	26–37	35–46	45–59	53–68	60–76	70–90	63–80	45–56
1·030	9–12	11–15	16–21	20–26	26–35	35–45	41–53	46–60	54–70	50–63	38–45
1·035	6–9	8–11	12–16	16–20	20–26	26–35	32–41	38–46	43–54	40–50	31–38
1·040	4–6	6–8	8–12	12–16	16–20	20–26	24–32	29–38	35–43	33–40	26–31
1·045	..	4–6	6–8	9–12	13–16	16–20	19–24	23–29	27–35	27–33	22–26
1·050	..	..	5–6	7–9	11–13	13–16	16–19	18–23	21–27	22–27	19–22
1·055	..	..	..	6–7	9–11	11–13	13–16	15–18	18–21	18–22	17–19
1·060	..	..	..	5–6	..	10–11	11–13	13–15	15–18	16–18	15–17
1·065	..	..	..	..	..	..	10–11	11–13	13–15	14–16	13–15
1·070	..	..	..	..	..	..	..	10–11	12–13	12–14	12–13
1·075	..	..	..	..	..	..	..	..	10–12	11–12	11–12
1·080	..	..	..	..	..	..	..	..	..	10–11	10–11

1. Cross-section of the Orifice.

The most usual type is the *concentric circular* orifice, Fig. 6, A, and we are concerned almost entirely with this in the present article. The chief advantage is that the circular hole can easily be machined to an exact diameter on which, of course, the accuracy of calibration depends. Furthermore, the shape of the orifice is completely specified by a single dimension, the diameter. It is therefore particularly suitable for the calculation of the discharge coefficient. The chief limitation consists in the fact that the coefficient cannot be calculated with certainty when the diameter of the orifice is made nearly equal to the bore of the pipe. This is mainly due to the difficulty of centring the orifice exactly in the pipe, and the result is that this type cannot be used at very high velocities in a pipe without causing large pressure differences which often cannot be tolerated. To overcome this difficulty 'chord' or 'segmental' type orifice plates are used, illustrated in Fig. 6, B and C. The 'chord' type, devised by Hodgson, has for its object concentrating the obstruction round the point at which the pressure connexions are made. At extremely high velocities, where the chord comes too close to the wall of the pipe, a small circular-shaped tongue can be used as the obstruction (Fig. 6, C) when the system becomes almost equivalent to a Pitot tube. In the 'slotted chord' type, a slot is cut in the plate opposite the pressure holes to avoid this Pitot tube effect and so reduce the differential pressure further.

These special types have to be calibrated individually, since all the details of their shapes are much more difficult to specify than the concentric circular type, and for this reason, where possible their use is avoided by increasing the size of pipe to reduce the velocity.

In general it may be said that the exact shape of the leading or upstream edge is extremely important and it will be noticed that in all three cases this edge is not rounded. This may be taken to be the basic distinction between an orifice and a nozzle. This point is referred to later.

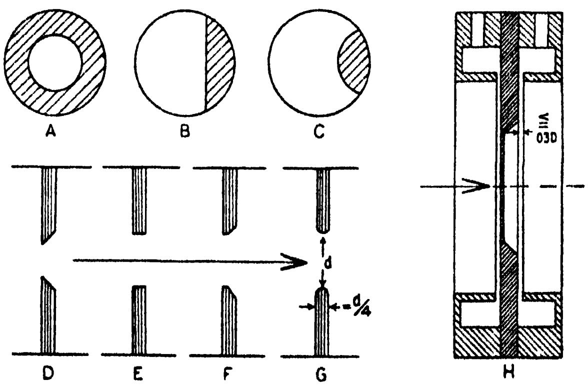


FIG. 6. Orifice metering.

Another point of importance to notice is that in all three cases the thickness of the plate at its smallest diameter should be very small compared with this diameter. Now if these two features are complied with, the characteristics of all three designs may be considered identical from a theoretical point of view with certain minor limitations at very low values of Reynolds numbers which may be neglected in practice. The distinction therefore lies in the practical considerations, and these are briefly as follows:

All three leading edges are 'sharp' as distinct from being

rounded, but the first is 'sharper' than the other two, which makes it more difficult to machine to a definite diameter which can easily be measured, and, furthermore, this diameter will be more liable to be changed in use due to corrosion or erosion.

As will be shown later, square or bevelled edges can both be treated as a sharp edge provided the ratio of thickness, t, to the orifice diameter, d, is less than about 1 : 8. Now with a small orifice in a large pipe, if the maximum thickness of the plate were made equal to the edge thickness, it would be difficult to make the plate quite flat, and also it might be seriously distorted by the differential pressure, particularly in the case of an overload. In practice, therefore, it is often essential to make the orifice from plates thicker than the edge thickness, and therefore bevelling is the general rule.

In order to make all orifices as 'dynamically similar' as possible, the V.D.I. [17, 1930] recommend using a definite relation between the plate thickness and the orifice diameter and making this thickness great enough to cover the most difficult case met with in practice (Fig. 6, H). This procedure involves using much thicker and therefore more expensive plates than are usually necessary, and does not show a marked improvement in accuracy over a properly proportioned 'thin' plate.

The effect of rounding or bevelling the upstream edge may here be referred to briefly. As mentioned above, Giese showed that some forms of rounding this edge had the effect of making the discharge coefficient less dependent on the Reynolds number. For instance, he found that by using a plate thickness a quarter of the orifice diameter and simply rounding both edges to a radius equal to half the plate thickness, as illustrated in Fig. 6, G, a nearly constant discharge coefficient could be obtained down to a Reynolds number in the orifice of about 1,000. Curves for two of these orifices are shown in Fig. 7 compared with curves for sharp-edged orifices.

This is an important effect, as it will be seen later that the rise in the discharge coefficient at low values of Reynolds number imposes a serious limitation to the accurate metering of viscous oils. This property has recently been further developed by George Kent and Company in the form of a thin orifice with a conical entrance, followed by a parallel part somewhat similar to the standard bevelled-edge orifice shown in Fig. 6, F, with the flow reversed, known as the 'PL' orifice. The length and angle of the cone and the length of the parallel part has to be varied to suit each diameter ratio, but when correctly proportioned an orifice of this type having a diameter ratio of 0·25 will give a discharge coefficient constant to within $\pm\frac{3}{4}$% down to a Reynolds number in the orifice of 180, and with a diameter ratio of 0·5 constant within ± 1% down to $R_e = 500$.

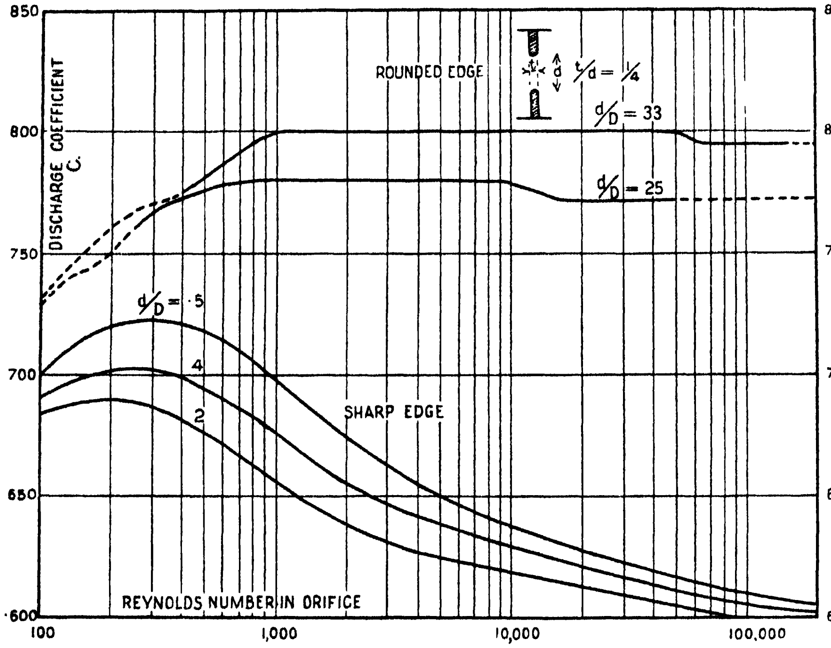


FIG. 7. Discharge coefficients.

As an example, it may be mentioned that for the latter orifice the conical surface makes an angle of 30° with the axis.

Another point of importance in connexion with rounded or conical orifices is that the discharge coefficient is much higher than for sharp-edged orifices, as can be seen from Fig. 7, so that the orifice of diameter ratio 0·5 mentioned above is equivalent to a sharp-edged orifice of diameter ratio about 0·6.

As in the case of special shapes of orifice the discharge coefficient of these orifices cannot be calculated in the ordinary way as its value depends on the exact proportions of the profile. The makers' calibration must then be relied on, and at present their use is confined to cases where the sharp-edged type cannot be used with sufficient accuracy or where circumstances do not permit allowances being made for the effect of the Reynolds number.

3. Pressure Connexions.

The calibration of any form of orifice will clearly depend on the position of the upstream and downstream connexions by which the differential pressure is measured, often referred to as 'taps'.

In the case of the usual type of thin-plate orifice there is a choice of positions along the pipe above and below the orifice plate, the best-recognized arrangements being shown in Fig. 8 as follows:

(1) Corner taps.
(2) Flange taps.
(3) 'Vena contracta' taps ($1D$ up and $0{\cdot}5D$ down).
(4) Pipe taps ($2{\cdot}5D$ up and $8D$ down).

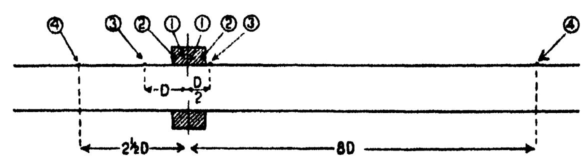


FIG. 8. Pressure connexions.

Arrangements (1) and (2) are essentially the same. In both cases the pipes leading to the recorder can conveniently

be fitted in the thickness of the flanges between which the orifice plate is clamped. There is nothing to be said for the use of flange taps, that is holes drilled straight through the centre of the thickness of the flanges, because this does not define the position of the holes exactly where they break into the main pipeline, as the thickness of the flanges may vary. The *one* essential feature for whatever arrangement is selected is that the position shall be precisely and rigidly standardized. This feature is complied with in the case of 'corner taps', provided the obvious precautions are taken, and this arrangement is illustrated in Figs. 6, H, and 9*a* (left-hand side).

Arrangements (3) and (4) both require connexions to be made in the pipe wall itself at some distance from the flange. This necessitates the welding of bosses on the pipe, or, alternatively, a saddle can be clamped round the pipe, and a pressure-tight joint can be made round the hole in the pipe wall by means of a soft gasket. The burr must be carefully removed where the pressure hole breaks into the main pipeline, as otherwise considerable error in the pressure readings may result.

The theory of 'vena contracta' connexions is that at approximately these positions, namely, one pipe diameter upstream and half a diameter downstream from the orifice, the pressure passes through a minimum in each case so that it does not change rapidly in value with position along the pipe in these regions.

There is little to be said in favour of 'pipe taps', namely, 2½ pipe diameters upstream and 8 diameters downstream from the plane of the orifice. At these positions it is considered that the *total loss of pressure* due to the orifice will be measured, and this is considerably less than the maximum pressure difference owing to the recovery of a fraction of the velocity head in the orifice. Furthermore, the pressure differences measured between points so far apart must depend to a considerable extent on the friction factor of the pipeline itself and not exclusively on the orifice. This fact alone makes the use of 'pipe taps' unsuitable for accurate measurement. Fig. 2 has been taken from Johansen's paper [11, 1929] and is generally representative of the pressure changes in the neighbourhood of a sharp-edged orifice at moderate and high Reynolds numbers. From these curves it will be seen that the pressures are changing rapidly near each face of the orifice plate, but brief consideration shows that this will not introduce any appreciable error in the case of corner taps, provided reasonable precautions are taken.

In general it may be said that corner taps are to be preferred for accuracy and measurement, but that 'vena contracta' taps are frequently used where circumstances make this form of connexion more convenient in practice.

4. Special Types.

There are some other useful arrangements at the orifice which should be mentioned, as they find application in special circumstances.

Fig. 6, H, shows a 'piezometer ring' applied to corner taps at an orifice, in which a narrow slot all round the circumference is used in place of the small holes mentioned above, and it will be seen that this design ensures that the *average* pressure round the circumference is obtained at the pipe connexion *A*. This has particular application when an orifice has to be used whose diameter is nearly equal to that of the pipe, since in such a case the exact centring of the orifice in the pipe is extremely important, and the use of a piezometer ring greatly reduces the error from this cause.

The range of flow which can be measured with a given orifice in a given pipe is very restricted, and may be taken to be only about 3:1, or less, for accurate work. The rate of flow to be measured must therefore be fairly accurately known beforehand, and a suitable orifice chosen for the purpose. If the flow is not known accurately enough, or if it varies widely, the orifice must be changed, and there are two ways of making this change without dismantling the system.

An arrangement similar to a gate valve is arranged in such a way that the orifice plate is built into the 'gate' and the gate can be withdrawn completely into a rather larger chamber than usual in the valve body. This chamber can then be isolated from the pipe by means of a special plug cock which allows the gate to pass through it when the plug cock is open. The chamber can then be opened to atmosphere and the orifice plate examined or changed if necessary. Another simple way of changing the size of the orifice to accommodate a wide range of flows is to use a very carefully made and fitted cock or valve, the fractional opening of which can be set exactly to certain values at which the whole arrangement has been calibrated.

Mechanical Conditions necessary for Accurate Measurement

The orifice is the least expensive but by far the most important part of the whole assembly. There is therefore every reason for taking the greatest possible care over the details of its design, construction, and installation. If this is done incorrectly, the meter readings may be quite misleading and there is no way of correcting the results given on the meter chart.

The orifice plate should be made of carefully selected material which will not corrode or erode under conditions of service, and the thickness should be adequate to prevent distortion. In this connexion it should be remembered that an orifice plate in a large line presents a large flat surface to any pressure difference which may be developed across the orifice due perhaps to a momentary overload.

The choice of material must rest on practical experience, but the following are usually recommended and found satisfactory:

Crude oil, fuel oil.	Stainless steel, Admiralty bronze.
Unrefined distillates.	Monel metal.
Natural gas.	Stainless steel.
Bleach liquor.	Ebonite.
Water and air.	Gun-metal or monel metal.
Sewage.	Stainless steel.
Steam.	Monel metal or stainless steel.
Ammonia.	Mild steel.
Sulphur dioxide.	Reinforced bakelite.
Coal gas, producer gas, &c.	Stainless steel.

The bore of the orifice should be turned extremely carefully to the correct diameter with the bore accurately parallel and dead smooth and with a perfectly square corner on the upstream side, but without any trace of burr and without any rounding of the corner.

Orifices in service must, of course, be examined periodically to see that they are still in good condition, since any corrosion or erosion of the bore or the corner on the upstream side will cause error.

Edge Thickness.

Beitler's experiments [3, 1933] show that when the thickness of the edge of the orifice is less than

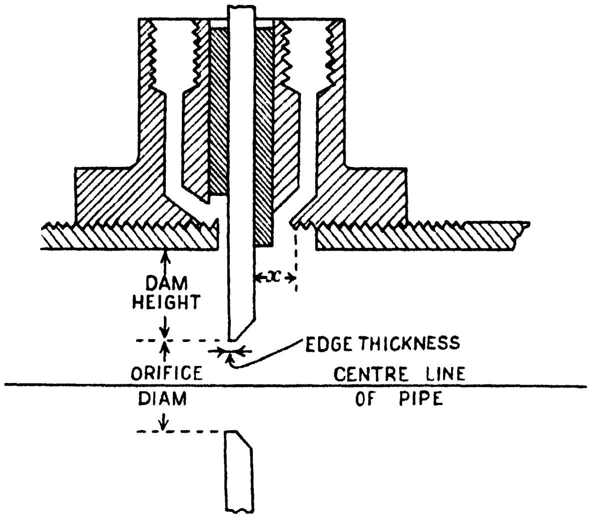
(*a*) $\frac{1}{8}$ the dam height [i.e. $t < \frac{1}{8}(D-d)$],

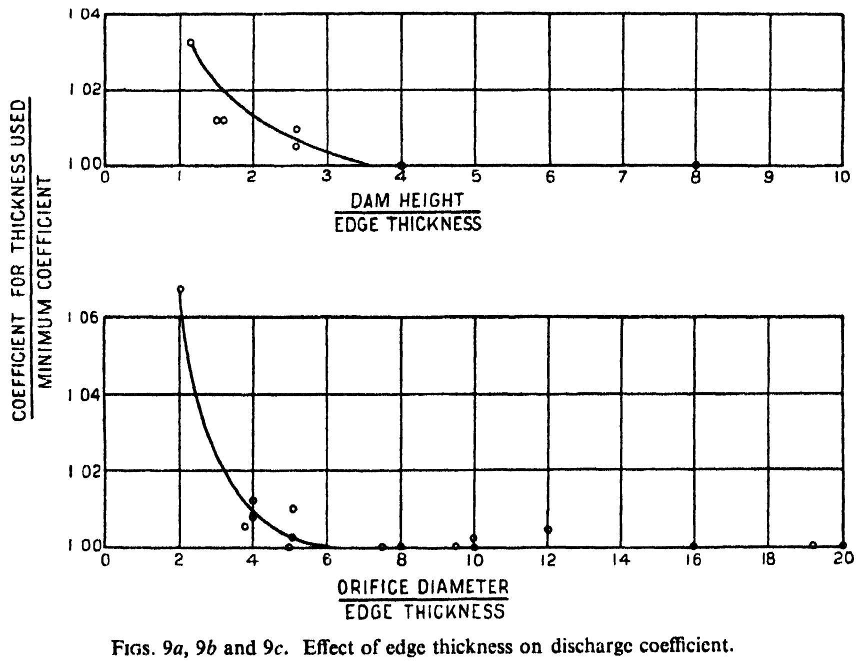
and (*b*) $\frac{1}{8}$ the orifice diameter (i.e. $t < \frac{1}{8}d$),

further reduction in thickness has no effect on the discharge coefficient in the turbulent region. Figs. 9*b* and 9*c* show the extent of the effect of edge thickness on the value of the discharge coefficient when these conditions are not complied with.

It is easy to bevel the plate on the downstream side at 45°, and ⅛-in. plate is the thinnest which is satisfactory for general accuracy is small, we need only be concerned with avoiding unnecessarily large edge thicknesses.

It is desirable wherever possible to leave a considerable margin over these limiting values, particularly so that the orifices shall be as nearly similar as possible when approaching the stream-line condition. For general use, therefore, the edge thickness should be less than $\frac{1}{16}$ of the





FIGS. 9*a*, 9*b* and 9*c*. Effect of edge thickness on discharge coefficient.

general use. Beitler recommends standardizing on ⅛-in. plate bevelled to $\frac{1}{32}$-in. edge thickness, and points out that this complies with both conditions (*a*) and (*b*) down to ½-in. orifice and a 1½-in. line at $d/D = 0{\cdot}80$.

Johansen [11, 1929] showed that at very low values of Reynolds numbers (< 100) there was an appreciable difference in the coefficient between a sharp-edged orifice and a bevelled edge with even a small square edge. This is no doubt due to the slightly increased viscous resistance offered by the parallel section of the orifice, but as the effect is small and occurs only in the region where the orifice diameter and ⅛ of the dam height with the limitation that for ordinary purposes the thickness should not be less than $\frac{1}{32}$ in., and where the orifice is large enough to allow it, it should be increased so as to give a less delicate edge.

The simplest rule to give to comply with these conditions using ⅛-in. plate as the standard thickness would be:

(*a*) Up to and including 1 in. orifice diameter. Bevel plate to $\frac{1}{32}$ in. on edge; above this diameter (and up to 2 in.) the bevel should be increased to $\frac{1}{16}$ in. unless the orifice is to be used in a line smaller than 3 in. diameter.

(b) Between 1 in. and 2 in. orifice diameter bevel plate to $\frac{1}{16}$ in. on edge.

(c) Above this diameter leave edge of plate $\frac{1}{8}$ in. thick unless the orifice is to be used in a line smaller than 8 in. diameter.

These rules ensure that the thickness of the edge will be equal or less than $\frac{1}{8}$ of the dam height even if the value of d/D is the maximum permissible (0·75) and equal or less than $\frac{1}{16}$ of the orifice diameter; but these rules make the edge thickness unnecessarily thin in some cases.

Alternatively a table can be given which gives the orifice sizes for which any of the standard bevels should be used Table (III).

TABLE III

Bevels required on Orifice Plates

Orifice Diameters for Various Widths of Edge

Based on: thickness $\leqslant \frac{1}{16}$ orifice diam., and $\leqslant \frac{1}{8}$ dam height)

Pipe diam. (in.)	*Bevel to $\frac{1}{64}$ in. on edge*	*Bevel to $\frac{1}{32}$ in. on edge*	*Bevel to $\frac{1}{16}$ in. on edge*	*No Bevel $\frac{1}{8}$-in. plate*	*Max. orifice diam. ($d/D=0\cdot75$) (in.)*
1	$\frac{1}{4}$ in. and over except $\frac{1}{2}$ in.	$\frac{1}{2}$ in. only	..	..	$\frac{3}{4}$
$1\frac{1}{2}$	$\frac{1}{4}$ to $\frac{1}{2}$ in. and over 1 in.	$\frac{1}{2}$ to 1 in.	..	..	$1\frac{1}{8}$
2	$\frac{1}{4}$ to $\frac{1}{2}$ in.	$\frac{1}{2}$ in. and over except 1 in.	1 in. only	..	$1\frac{1}{2}$
3	,,	$\frac{1}{2}$ to 1 in. and over 2 in.	over 1 in. to 2 in.	..	$2\frac{1}{4}$
4	,,	$\frac{1}{2}$ to 1 in.	over 1 in. to 3 in.	2 in. only	3
6	,,	,,	over 1 to 2 in. and over 4 in.	over 2 to 4 in.	$4\frac{1}{2}$
8	,,	,,	over 1 to 2 in.	over 2 in.	6
10	,,	,,	over 1 to 2 in.	over 2 in.	$7\frac{1}{2}$
12	,,	,,	over 1 to 2 in.	over 2 in.	9

Position of Pressure Holes.

As has been mentioned above, the only position which can be specified exactly without regard to the pipe diameter or the orifice diameter is the corner between the face of the orifice plate and the inside surface of the pipe. Corner taps are generally regarded as the most satisfactory from the point of view of accuracy, but 'vena contracta' taps are not infrequently used because it is more convenient in certain circumstances to take the pressure connexions from the pipe itself instead of from the flanges. When this is done it is most important that no burr shall be left on the inside of the pipe at these pressure connexions.

Corner taps only require that the pressure holes, drilled most of the way through in the middle of the flange, should be counter-bored from the inside corner as shown in Fig. 9*a*. The pipe should be screwed well into the flange. It may even project slightly beyond the face of the flange if the gasket is cut back so as to be well clear of the pipe, as shown on the left of the figure.

If the pipe is left at a distance behind the face of the flange and the gasket is allowed to project, the centre point of the opening between the end of the pipe and the face of the gasket is at a certain distance x from the face of the orifice plate as shown on the right of Fig. 9*a*, which, from Fig. 2, would be expected to cause considerable error in the readings. If the error is calculated from these curves, it will be found that the error should only be about $\frac{3}{4}$% on the calculated flow in the worst probably case, but there is some evidence that the results in practice are substantially worse than these curves would indicate.

Installation of the Orifice in the Pipeline.

The details of the arrangement of the orifice in the pipeline and of the piping, drains, cocks, vessels for liquid seals, &c., for connecting the meter to the orifice are dealt with very thoroughly in several publications, and notably the A.S.M.E. [15, 1933]. Only the important features from the point of view of accuracy of orifice calibration are dealt with below.

Centring of the Orifice.

Care must be exercised in centring the orifice plate accurately so that the centre of the orifice coincides accurately with the centre of the pipe. This is particularly important when the diameter ratio is large, that is, 0·7 or over, and when only one pair of pressure holes are used for measuring the differential pressure. The reason for this is not hard to see. If the orifice is displaced so that its centre is farther from the pressure holes, the dam height on this side becomes too large and the differential pressure is consequently too high. With large diameter ratios, the stagnant area behind the orifice is too small to allow much equalization of pressure from one side of the orifice to the other, and when the diameter ratio is about 0·75 the greatest care in centring is necessary to avoid errors unless a piezometer ring is used for the pressure connexions, as shown in Fig. 6, H.

Such an arrangement is a great improvement over a single hole for all accurate work, as it not only eliminates most of the pressure differences round the orifice due to inaccurate centring, but also the effects of local irregularities in the pipe surface.

These considerations make the use of diameter ratios greater than 0·75 to 0·80 unsuitable for ordinary work where the orifice cannot be calibrated *in situ*.

Length of Straight Pipe required.

In order that the calibration of an orifice shall be unaffected by local circumstances, it is necessary to allow a considerable length of straight pipe before the orifice in order to allow any disturbances in the fluid caused by bends, elbows, valves, &c., to subside before the fluid reaches the orifice. A certain but much smaller length is necessary after the orifice also to prevent any disturbance from a pipe-fitting being transmitted back to the orifice and so affecting its calibration.

The length of straight pipe required before and after an orifice to reduce the maximum error to less than $\pm 2\%$ was investigated by the A.S.M.E. [15, 1933], and the more important results are given in Fig. 10 in terms of pipe diameters. There are no figures to indicate the lengths required for better accuracy than 2%, but it may be guessed that to reduce the error due to this cause to a negligible value the lengths should all be doubled.

It will be noted that all these lengths must be very much greater when the diameter ratio is high, as the orifice is then very much more sensitive to disturbances of all kinds.

It will also be seen that an excessively long straight pipe is necessary after a partly closed valve, and this condition should always be avoided wherever possible.

In certain circumstances, fortunately not common in the oil industry, it is almost impossible to arrange for a great enough length of straight pipe before an orifice, and in

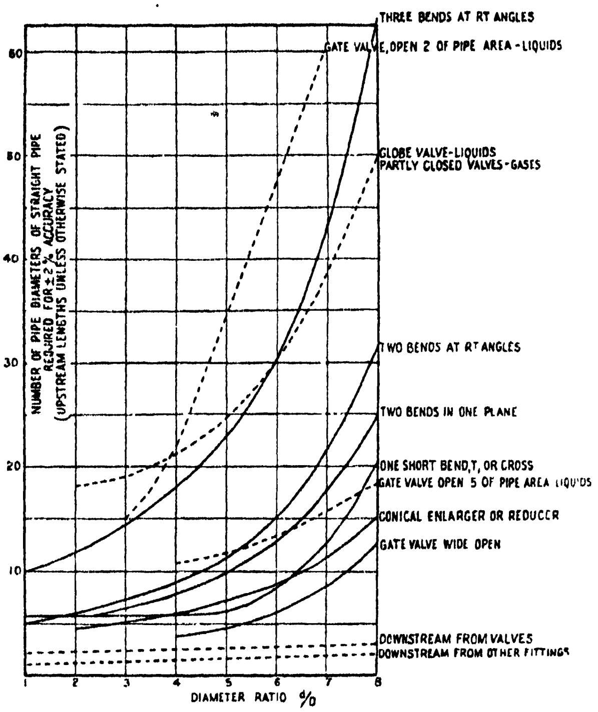


FIG. 10. Length of straight pipe required.

such cases the use of straightening vanes are recommended by the A.S.M.E. These consist of a sheet-metal honeycomb structure which in effect divides the pipe into a number of smaller pipes over a length of several pipe diameters, thereby eliminating most of the non-axial velocities, but they may be useless after a bend or elbow when the trouble is due rather to abnormal velocity distribution. In such cases a properly designed set of guide vanes at the corner may be very effective.

The use of such vanes reduces the length of straight pipe required for $\pm 2\%$ accuracy according to the A.S.M.E. Tests to less than 15 diameters in the worst cases. Further details can be obtained from the A.S.M.E. Report itself.

Use of Liquid Seals.

It is often desirable and sometimes essential to prevent the fluid which is being metered at the orifice from reaching the recording meter; for instance, if the fluid is corrosive, or if the fluid is so viscous at ordinary temperatures that its presence in the relatively long pipe connexions to the meter would render it sluggish or inoperative.

In such cases the meter is completely filled with a suitable non-miscible liquid above the mercury, and two relatively large vessels are provided, one in each pressure connexion between the orifice and the meter, arranged so that the piping to the meter can be also filled with the liquid, while the surface of separation between the sealing liquid and the fluid being metered is in the vessel in each pipeline.

From the point of view of maintaining the accuracy of the meter calibration the horizontal cross-section of the sealing vessels must be so large that displacement of the mercury in the meter due to change in differential pressure does not cause an appreciable pressure difference due to displacement of the surfaces of separation in the sealing vessels.

In the case of liquids, the difference in density of the liquid being metered and the sealing liquid is usually quite small (say, 0·5 maximum), while that of the mercury in the manometer is high (13·57). In order to be able to neglect the effect entirely, the horizontal cross-section of the sealing vessels at the surface of separation is made about 30 times that of the manometer in the meter, in which case the error is about 0·1% on the differential pressure or 0·05% on the calculated flow, which is quite negligible. Short sections of 6-in. pipe are often used for the purpose in practice and are found quite suitable.

When liquid seals are used due allowance must, of course, be made for the density of the sealing liquid above the mercury in the meter.

Flow Conditions for Accurate Metering.

The following are the general requirements for accurate metering with sharp-edged orifices.

The Reynolds number should be as high as possible for two reasons. Firstly, the values of the discharge coefficient are more accurately known and depend less on the accurate estimation of R_e, and the overall accuracy of an orifice meter is higher in this region. Secondly, the value of M is dependent on the rate of flow through the orifice, and therefore varies with the percentage of full-flow recorded by the meter. This variation is negligible at values of R_e above 40,000, but as can easily be seen from Fig. 5, it is of great importance in the critical region. For instance, under certain conditions, using a ratio of $d/D = 0{\cdot}75$, the value of R_e at full flow may be 5,000 and the value of $M = 1{\cdot}168$. At one-third full flow the value of R_e will be 1,670 and $M = 1{\cdot}440$. In this case an error of 19% would be made unless M is calculated for the *actual* flow being measured and not for full flow, a proceeding which would be very laborious if it had to be adopted frequently.

The value of d/D should, if possible, be less than 0·75, since it is found that errors occur with orifices giving a greater ratio than this owing, among other things, to difficulty in centring them accurately in the pipe. At low values of R_e it is better to keep the value of d/D below 0·5 if possible, since M does not increase so rapidly in the critical region for lower values of d/D, and hence the variation of M with percentage of full flow is decreased.

It should be pointed out that these difficulties are overcome to a large extent by the use of the special types of orifice plate such as the 'PL' orifice developed by Kent's, or in certain cases by the use of flow nozzles.

Pulsations in the flow must be avoided since there are two sources of error which may be introduced from this cause. When the flow fluctuates rapidly, the recording meter must be prevented from following the fluctuations in differential pressure in order to avoid the lines on the chart from running into each other. This can be done by damping the meter by means of a throttle on one of the pressure lines. When the range of fluctuation of the differential pressure is small compared with its mean value, then this method does not introduce serious error, but when this is not the case, a substantial error is introduced owing to the fact that the meter will show approximately the mean differential pressure, whereas the flow depends on the square root of the differential pressures. There is no known means of damping a meter in such a way

that it will give the correct reading in such a case, and the only way of obtaining an accurate measurement of the flow by an orifice meter is to eliminate pulsation in the flow at the orifice. This can be done by introducing air chambers into the main pipeline, followed by a suitable throttling device. The size of air bottle and throttle could be arrived at by means of an elaborate calculation if the wave-form and frequency of the pulsations are known, but in practice as large a capacity as possible is used, followed by enough throttling to prevent substantial changes of differential pressure as indicated by an undamped indicating device. This may be the meter itself if the frequency of the pulsations is low; otherwise it is not safe to assume the pulsations have been removed until an instrument, such as an engine indicator, has been fitted, as recommended by the A.S.M.E [15, 1933]. Certain typical arrangements for reducing the pulsation in the flow are also given in that publication.

When there is bad fluctuation in the flow in the case of gas and adequate throttling cannot be applied at the pressure connexions at the orifice, and if the pressure connexions from the primary element to the secondary device are filled with gas, a condition of resonance may be set up in these pipes and may cause spurious readings. This can be overcome by splitting up the connexions into a series of capillaries or the equivalent, for instance, by filling with lead shot. In such cases dirt and moisture must be excluded.

Selection of a Suitable-sized Orifice.

When an orifice meter is to be installed, the following factors are usually known beforehand: the size of the pipe, the nominal differential pressure for full-scale reading, the maximum rate of flow and the specific gravity of the fluid,

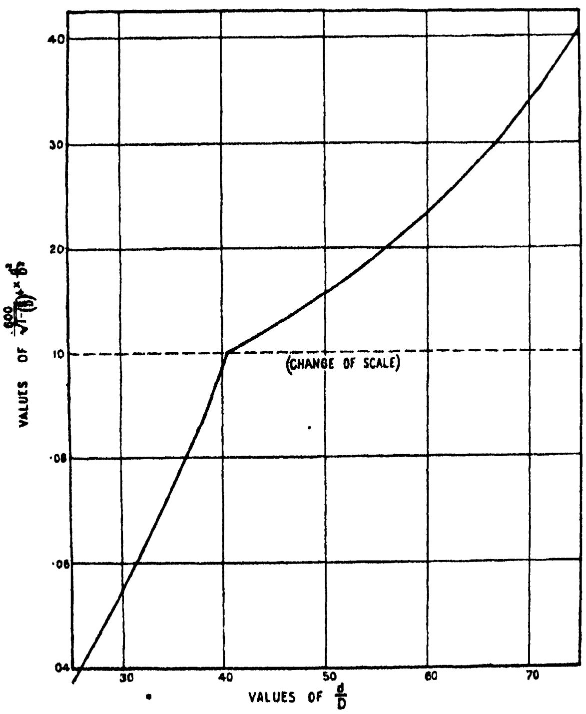


FIG. 11.

and the temperature and pressure at the orifice. With these data the appropriate orifice diameter can be calculated directly by the use of Fig. 11.

For example, in the case of a meter for measuring liquids without the use of seals, the meter being calibrated with water above the mercury, equation (12) can be rearranged after dividing both sides by D^2, thus:

$$\frac{q_{60}}{D^2}\times\frac{1}{283\cdot3\sqrt{\left\{\frac{(13\cdot57-S_m)S_f}{12\cdot57(S_{60})^2}\right\}}\times M\sqrt{h}}=\frac{0\cdot600}{\sqrt{\left\{1-\left(\frac{d}{D}\right)^4\right\}}}\times\frac{d^2}{D^2}. \qquad (15)$$

All values are known on the left-hand side for full flow with the exception of M, which in the first instance should be assumed equal to 1·0. The value of the right-hand side can therefore be calculated. This function is plotted on Fig. 11 against the diameter ratio, d/D. The value of this ratio can therefore be read off and d worked out directly.

The value of d so obtained is then used to work out R_e for the orifice, and M is then found by reference to Fig. 5. This value of M is then substituted in equation (15) and a more accurate value of d worked out if necessary. This value will always be found to be accurate enough without repeating this trial and error process. The procedure is exactly similar for selecting an orifice for metering gases.

Limiting Values of d/D.

When the size of the orifice has been calculated it may be found that the required value of d/D given by Fig. 11 is higher than 0·75.

Now the use of a diameter ratio greater than 0·75 is considered bad practice for normal work, since the calibration for larger orifices is liable to be in error as explained above. In such a case arrangements should be made to reduce the diameter ratio which can be done either by fitting the orifice in a larger pipe or by using a meter having a greater maximum differential pressure.

There are other circumstances which may make the value found for the diameter ratio, by the above method, unsuitable. For ordinary work it is very desirable to be able to calculate the appropriate value of M for the full-flow condition and use this value for all values of the flow down to the smallest fraction which can usefully be read on the meter. As pointed out above, when the value of M changes rapidly with R_e there would be very considerable errors in the fractional flow readings if this were done.

It is necessary, therefore, to limit the use of a constant value of M to those regions on the M chart (Fig. 5) where only a reasonably small error is introduced from this cause. It will be seen by inspection of Fig. 5 that the lower limit of R_e in this respect is much higher for large than for small values of d/D.

In the short table IV below are given these minimum values of Reynolds number for various values of d/D calculated for full flow which can be used without causing an error of more than 2% at half full flow (i.e. one-quarter of

TABLE IV

Limiting Values of d/D and R_e

Diameter ratio d/D	*Lower limit of Reynolds number calculated for full flow*
Up to 0·30	4,000
Over 0·30 to 0·40	5,000
Over 0·40 to 0·45	7,500
Over 0·45 to 0·50	10,000
Over 0·50 to 0·55	20,000
Over 0·55 to 0·70	25,000
Over 0·70 to 0·725	30,000
Over 0·725 to 0·75	50,000

the maximum differential pressure) due to the use of a constant value of M chosen for the full-flow condition.

It is further recommended, therefore, that wherever it can possibly be avoided the use of a sharp-edged orifice with a diameter ratio of more than 0·50 should not be used when the Reynolds number is less than 10,000.

Apart from the change in the value of M over the range of flow covered by the meter, the actual value of M becomes very much less certain for high values of d/D when the value of R_e is less than about 10,000.

Evaluation of Correction Factor, M

As pointed out above, the correct value of M to be used in determining the discharge coefficient should strictly be that corresponding to the Reynolds number calculated for the actual rate of flow through the orifice at the particular differential pressure considered. This, of course, implies that, in regions where the value M is changing appreciably with R_e, the rate of flow is not quite proportional to $\sqrt{h}$. This was recognized, for instance, by Barnes [1, 1934] even with water flowing through a 36-in. diameter orifice in a 60-in. main at Reynolds numbers up to 2,000,000. For this particular case he gives Q proportional to $h^{0 \cdot 4980}$.

This proceeding is, however, impracticable for routine work and it is therefore necessary to choose a suitable value of M which will be representative of the whole useful range of flow covered by one particular arrangement of orifice plate and recording meter with the fluid under consideration. The procedure recommended for normal cases given by Table IV is therefore as follows:

1. Calculate the Reynolds number for full flow in the orifice as installed for representative conditions of density and viscosity of the fluid, then take the value of M corresponding to this Reynolds number from Table II, but using the next lower range of R_e (i.e. the next higher value of M) when the calculated value of R_e comes near the bottom of a group in the table.
2. When the properties of the fluid at the orifice change over a reasonably small range (due, for instance, to change of temperature or pressure), do *not* alter the value of M even if the new value of R_e brings it into a different group in the table.
3. If the orifice plate or the meter size is changed and the calculated value of R_e brings it into a new group in Table II, the value of M *should* be altered accordingly.

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THE MEASUREMENT OF GAS WITH PARTICULAR REFERENCE TO NATURAL PETROLEUM GASES

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Physical Characteristics of a Gas. The Gas Laws

If a given mass of gas is confined in a container of variable volume, v—for example in a cylinder with a movable piston—the absolute pressure, p, exerted by the gas on the walls of the container varies inversely as the volume and directly as the absolute temperature, T. Letting the subscripts 1 and 2 refer to any two sets of conditions of the same mass of gas, the foregoing statement may be expressed by the equations:

$$\frac{p_1}{p_2} = \frac{v_2}{v_1} \times \frac{T_1}{T_2} \quad \text{or} \quad \frac{p_1 v_1}{T_1} = \frac{p_2 v_2}{T_2}. \tag{1}$$

Or, since the density, ρ, of the mass of gas varies inversely as the volume occupied, we have the relation $v_2/v_1 = \rho_1/\rho_2$, and equation (1) may be written in the equivalent form

$$\frac{p_1}{p_2} = \frac{\rho_1}{\rho_2} \times \frac{T_1}{T_2} \quad \text{or} \quad \frac{p_1}{\rho_1 T_1} = \frac{p_2}{\rho_2 T_2}. \tag{2}$$

In these equations, and also in those that follow throughout this article, the pressures are absolute pressures. Likewise, the temperatures are absolute temperatures.

Equation (1) or the equivalent (2) is frequently referred to as the combined law of Boyle and Charles, and also as the ideal gas law.

If $T_2 = T_1$ equations (1) and (2) reduce to

$$\frac{v_1}{v_2} = \frac{\rho_2}{\rho_1} \;(a) \quad \text{and} \quad \frac{\rho_2}{\rho_1} = \frac{p_2}{p_1} \;(b). \tag{3}$$

Equation (3b) or its equivalent

$$p_1 v_1 = p_2 v_2 \tag{4}$$

is a statement of Boyle's law, and gives rise to the common conception of the compressibility of a gas.

As is suggested by the term 'ideal gas law', equations (1), (2), (3), and (4) are not exactly true for any real gas, although they are very nearly true for such gases as air and hydrogen at moderate pressures. Different gases depart from Boyle's law by varying amounts, and both the amount and direction of the departure depend upon the temperature. With most of the petroleum natural gas mixtures, the density increases with rising pressure somewhat faster than is indicated by equation (3 b). As far as required for most problems of gas measurement, this behaviour may be represented by writing equations (3) and (4) in the modified form

$$\frac{\rho_2}{\rho_1} = y\frac{p_2}{p_1} \quad \text{or} \quad \frac{v_1}{v_2} = y\frac{p_2}{p_1}, \tag{5}$$

in which y is a numerical factor slightly greater than 1·00 for the gases just mentioned. (It is important to note that there are exceptions to this statement; one is that for most gases at very high pressures and temperatures, y is less than 1·00; also for hydrogen and helium under ordinary conditions, y is less than 1·00. For a more detailed treatment of these variations reference should be made to some of the literature on the subject [1, 1930; 9].

For convenience in gas-measurement work, this excess of compressibility over what is indicated by Boyle's law has been called 'supercompressibility', and the factor represented by y has been called the 'supercompressibility factor'.

In the calculation of gas quantities it is frequently desired to take account of the amount of water vapour with the gas and to determine the proportion of dry gas in the moist gas mixture. For this purpose it is sufficiently accurate to treat the mixture of gas and water vapour as if each of the two components satisfied the ideal gas equation and exerted its own partial pressure independently of the presence of the other component. Let

p_w = partial pressure of the water vapour,
p_g = partial pressure of the dry gas,
$p = p_w + p_g$ = observed total pressure of the mixture,
v_1 = initial volume occupied by the mixture at p_1, T_1,
v_2 = volume which would be occupied by the dry (i.e. water-vapour free) gas at p_2, T_2.

By the definition of p

$$p_g = p - p_w. \tag{6}$$

Now if we substitute $(p_g)_1$, or its equivalent $(p-p_w)_1$, for p_1, in equation (1) we have upon rearranging

$$v_2 = v_1 \frac{(p-p_w)_1}{p_2}\frac{T_2}{T_1}. \tag{7}$$

If it is known that in the mixture the water vapour (or steam) is at the point of saturation, then the value of p_w corresponding to T_1 may be obtained from any steam table. Very frequently it will not be known whether the water vapour is at the point of saturation or below it, and it will therefore be necessary to determine p_w by some form of hygrometric measurement. The more familiar method is with the wet and dry bulb psychrometer, although the dew-point method and the meter and drying tube are sometimes used [7]. A detailed discussion of hygrometry is beyond the scope of this article.

Standard Conditions to which Volumetric Measurements of Gas are referred

If gas quantities were measured and expressed in terms of mass (lb.), the pressure, temperature, and volume occupied would be of secondary interest. But, since it is almost universal practice to express gas quantities in terms of volume (cu. ft.) which, as already shown varies inversely with pressure and directly with temperature, it is always necessary to state the pressure and temperature along with the volume. Moreover, if two gas volumes are to be compared, it is necessary that they be at the same conditions of pressure and temperature, or that they be referred to the same conditions.

Before discussing the conditions to which gas measurements may be referred for comparison, it will be desirable to define the cubic foot, the unit of quantity, as the term

is used in commercial practice. The definition that has been very generally used is [6]: 'A cubic foot of gas is that quantity of gas which, saturated with water vapour at a temperature of 60° F. and under a pressure of 30 in. of ice-cold mercury at standard gravity, occupies a space of 1 cubic foot.' As a basis for the sale of gas to consumers, particularly domestic and small industrials, the following approximate definition is generally used: 'A cubic foot of gas is considered to be that quantity which, under the conditions of temperature, pressure, and humidity existing at the time and place of measurement, will occupy 1 cubic foot.'

The standard conditions for comparison set up by the first definition are: A temperature of 60° F. and a pressure of 30 in. of mercury. By common practice in some industries, and by agreement, these conditions are frequently modified. For example, the pressure of 30 in. of mercury may be replaced by 14·40 lb. per sq. in., or 14·40 plus 2, 4, or 8 oz. Using 14·73 lb. per sq. in. is practically equivalent to 30 in. of mercury. Also, 68° F. (20° C.) is now very extensively used as a reference temperature.

The basic definition was originally written for manufactured fuel gas which always contained saturated water vapour. Natural gas of petroleum origin is often very nearly dry, and, for this reason, the requirement that the gas be mixed with saturated water vapour might well be omitted when defining a cubic foot of petroleum gas.

Gas Meters. Displacement Type

In the measurement of gas to both domestic and industrial consumers, at relatively low rates of flow and near atmospheric pressure, it is the universal practice in the United States to use a displacement meter of the bellows type. These meters measure the gas volumetrically by alternately filling and emptying chambers which have movable bellows type partitions. The reciprocating motion of these partitions actuates a counter, or index, by which is recorded the volumetric value of the number of times the chambers are filled and emptied. As these meters ordinarily operate at pressure only slightly above atmospheric, it is not customary to make any correction for pressure variations from a stated or implied pressure base. Neither are there made corrections to a temperature base.

For measuring gas where the rate of flow may range up to several thousands of cubic feet per hour, one or more larger displacement meters, usually of the bellows type, are used. Rates of flow up to about 17,000 cu. ft. per hour may be measured by single meters of the bellows type.

Another type of displacement meter particularly well adapted to measuring medium and large rates of flow is the lobed impeller or rotary displacement meter. Rates of flow up to 1,000,000 cu. ft. per hour can be measured by single meters of this type.

When the line pressure at which the meter is to operate is considerably above atmospheric, displacement meters with cast iron or pressed steel cases are used. Meters of the bellows type with these heavier cases may be used on line pressures up to about 300 lb. The usual case of the lobed impeller meter can be used on line pressures up to about 25 lb. gauge. For use at higher pressures, it has been found more satisfactory to enclose the meter in a high-pressure chamber than to increase the strength of the meter case.

When used at these higher line pressures, the meter index gives the volume at these pressures. For purposes of sale, it is necessary to reduce the meter-index reading to the standard or contract base pressure, which may be done by use of equation (1), (4), or (5), letting p_2 represent the base pressure. In order to make this reduction, a record of the pressure at which the meter operated during the interval in question is needed. This may be obtained most conveniently with a recording pressure-gauge connected to the meter and driven by a clock or by the meter index. In addition to the time-pressure record, the clock-driven gauges usually give an additional record of the meter volume so that the volume at the reference pressure may be computed directly from the chart. Instead of having to make the volume reduction computation manually, it may be done mechanically by one of several types of attachments which will reduce the meter registration to the base pressure and integrate the volume thus obtained on a separate direct-reading index. These mechanical pressure-volume reduction attachments can be made to compensate for the supercompressibility of the gas, which, of course, would be done when the volume reduction is made manually.

A correction for variations of the gas temperature from the reference or contract-base temperature has seldom been made in the past. Such a correction is receiving more attention and now is often made. This correction may be made manually from an observed or recording thermometer record of the gas temperature, or it may be made automatically by an attachment which will give directly the integrated volume at the reference temperature. Whether made manually or mechanically, this temperature correction can be combined with the pressure correction, when that is made, to give the volume at the base pressure and temperature.

All the displacement type meters have the property of measuring all the gas that flows through them regardless of the rate of flow. (With the lobed impeller meters there is a small slippage which varies from practically zero above one-fourth capacity to 2–3% at very low rates. This slippage is corrected for by calibration.) Moreover, these meters maintain a high degree of accuracy over their entire capacity range. The smaller meters of the bellows type are frequently so adjusted that their indications are not in error more than ½% over their entire capacity range. Using these meters at high-line pressures does not, by itself, affect their accuracy, since their volumetric displacement remains the same, provided the pressure-drop across them does not exceed 1·5–2·0 in. of water column.

Head or Rate of Flow Meters

For the measurement of natural gas in the field, as encountered in connexion with the production of petroleum, the orifice meter is probably used more than all other kinds. It is also becoming more and more used in intermediate and final sales of gas where the rate is relatively steady. While at first glance the orifice meter may appear exceedingly simple to construct and operate, it is, in fact, almost the reverse. Because of this, and also because the orifice meter now occupies so important a place in the petroleum and fuel-gas industries, it will be appropriate to give in some detail the essential points on the construction, installation, and operation of orifice meters.

Construction and Installation. The pipe which is to form the orifice meter run must be carefully selected for roundness and nearness to the specified size. The interior surface should be free from rust, scale, and blisters. The flanges or fitting for holding the orifice plate should be so designed

and attached to the pipe that the inner surface of the pipe extends up to the orifice plate without a recess next to the orifice plate of more than ¼ in. as measured parallel to the axis of the pipe.

On the upstream side of the orifice the pipe is to be straight and unobstructed for lengths varying from about 10 to over 60 times the pipe diameter. The length of pipe depends upon the type of fitting preceding it and upon the ratio of orifice to pipe diameter. The lengths of the meter run, i.e. the straight pipe, may be reduced to values of from about 6 to about 15 pipe diameters by placing straightening vanes or honeycomb section near the upstream end.

On the downstream side of the orifice the length of the meter run should extend from 2 to 5 pipe diameters beyond the downstream pressure tap.

The following figures, 1 to 5, give the minimum lengths of straight pipe which should precede and follow an orifice flange or fitting [10]. Whenever circumstances permit

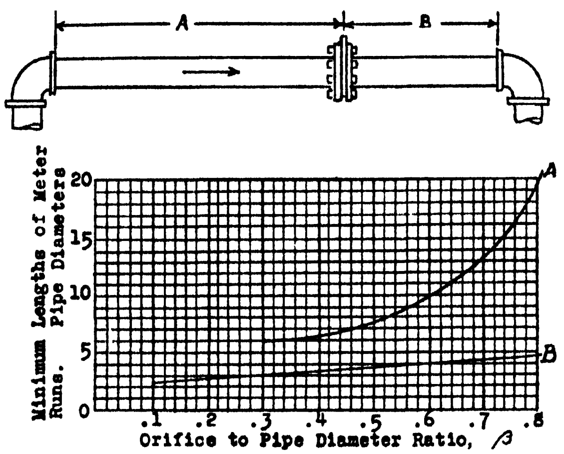

FIG. 1. Orifice meter preceded by a single ell or tee.

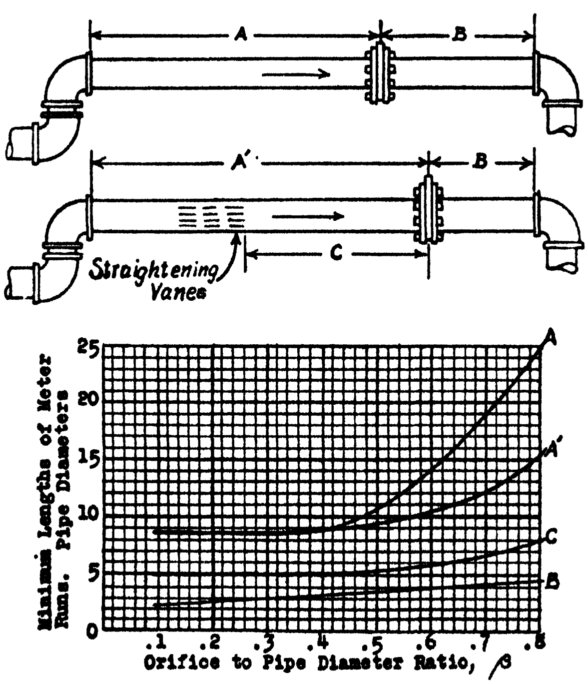

FIG. 2. Orifice meter preceded by two ells, two tees, or ell and tee, both in the same plane, and less than ¼A apart.

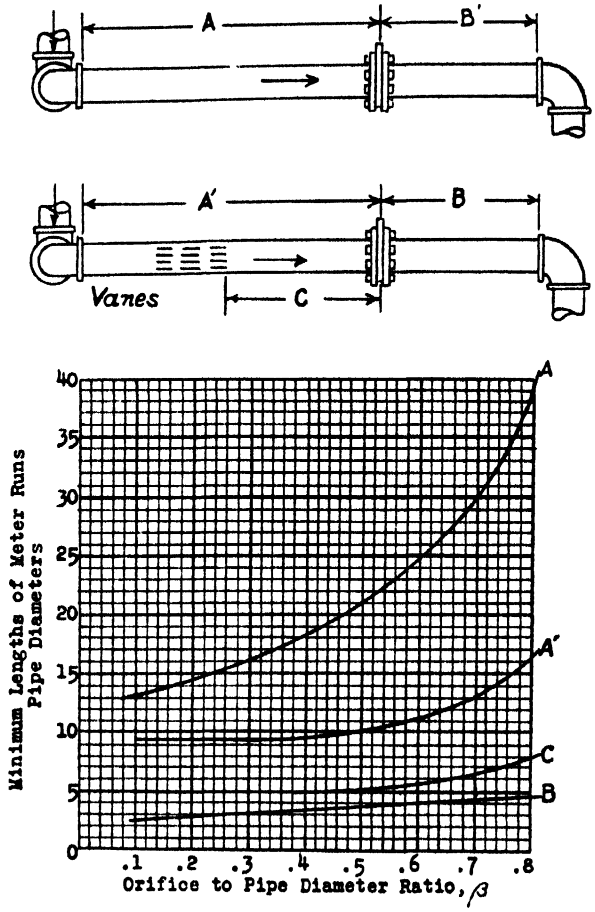

FIG. 3. Orifice meter preceded by two ells, two tees, or ell and tee, not in the same plane, and less than ¼A apart.

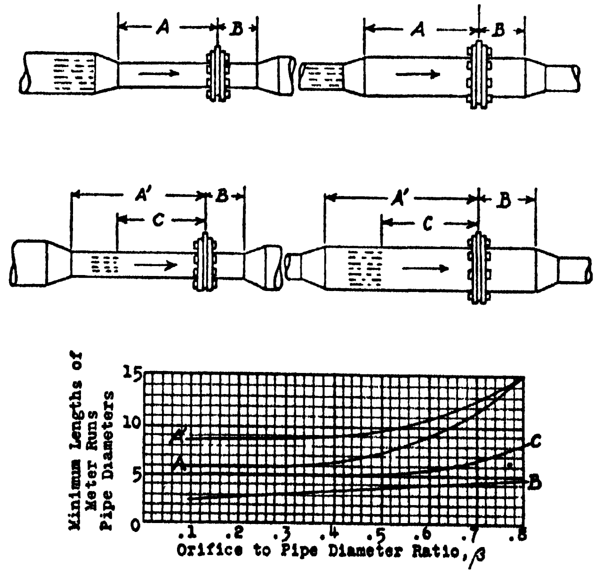

FIG. 4. An orifice meter preceded by either a reducing or expanding swedge.

more than these minimum lengths should be used. In using these figures the following rules should be observed:

1. Whenever designing an orifice installation in which the size of the orifice may be changed, the lengths of the

meter runs should correspond to or exceed those for the largest orifice (and therefore for the largest value of β) that will be used.

2. Whenever the pressure taps are located *more* than 1 pipe diameter from the orifice plate the dimensions A, B, &c., are to be measured *from the pressure tap* instead of from the orifice plate.

3. Regardless of how much the lengths A' and C may be increased beyond the minimum values indicated, the difference (A'-C) should never be less than the amount indicated by the figures.

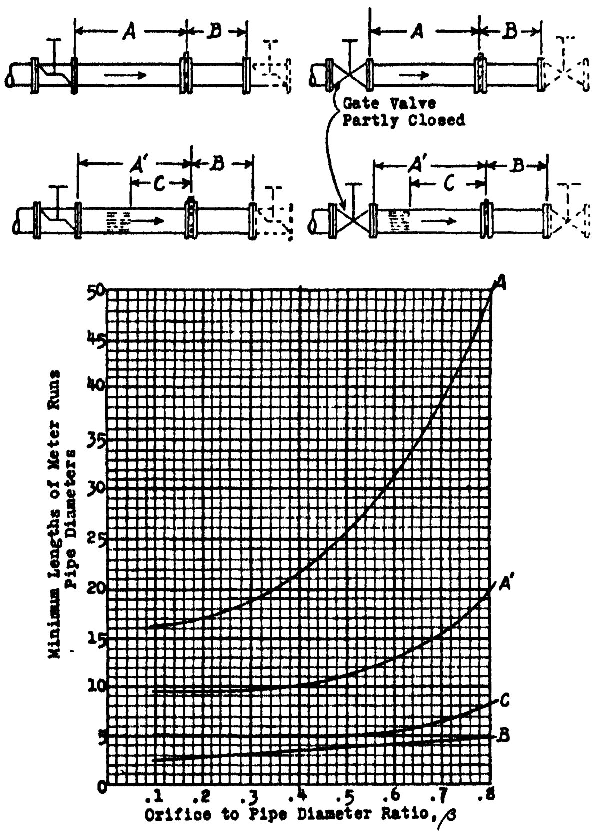

FIG. 5. An orifice meter preceded by a globe or pressure-regulating valve, or a gate valve used for flow regulation.

The orifice plate material should be either machine steel or a non-rusting steel. The thickness of the material should be sufficient to prevent dishing under the differential pressure to which it may be subjected. On the other hand, it will seldom be necessary to use heavier than $\frac{1}{4}$-in. material except in very large pipes—16 in. and over; $\frac{1}{8}$-in. material is most commonly used. Also, when clamped between flanges, the finished orifice plate should not deviate from absolute flatness by more than 0·01 in. per inch of pipe radius. (This criterion for flatness is offered as seeming reasonable, although test data to substantiate it are lacking.)

The orifice must be carefully bored and the upstream edge made square and sharp so that it will not appreciably reflect a beam of light. The width of the cylindrical surface of the orifice should not exceed any of the following:

1. $\frac{1}{50}$ of the pipe diameter, D_1.
2. $\frac{1}{8}$ of the orifice diameter, D_2.
3. $\frac{1}{4}$ of the dam height, $\dfrac{D_1-D_2}{2}$.

If the thickness of the plate is greater than any of these limitations, the downstream corner of the orifice should be bevelled at an angle of 45° or less to the surface of the plate. When using a bevelled plate one must be very careful to have the bevelled side face downstream.

The three locations for the pressure taps most commonly used in the United States are:

1. The centre lines of both upstream and downstream tap are to be 1 in. from the adjacent face of the orifice plate. If a $\frac{1}{16}$-in. gasket is to be used the holes should be centred $\frac{15}{16}$ in. from the bearing face of the flanges. Hereafter, taps located at these distances will be referred to as Flange Taps.

2. The centre line of the upstream pressure tap is to be 1 pipe diameter from the upstream face of the orifice plate. The centre of the downstream tap will be between 0·8 and 0·4 pipe diameter from the upstream face of the orifice plate, depending on the diameter ratio of the orifice, as shown by Fig. 6. Pressure taps located at these positions will be referred to as Vena Contracta Taps.

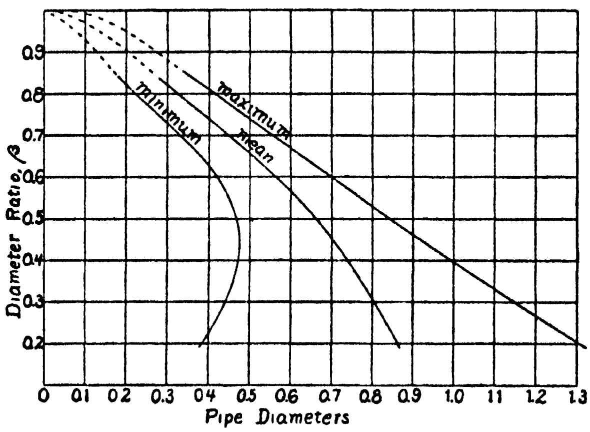

FIG. 6. Location for downstream pressure tap with vena contracta taps.

3. The upstream tap is located approximately $2\frac{1}{2}$ pipe diameters above the orifice plate, and the downstream tap approximately 8 pipe diameters below the orifice plate. Taps thus located will be referred to as Pipe Taps.

For the diameter of the pressure holes at the inner surface of the pipe, a convenient rule is that this diameter should not exceed $\frac{1}{8}$ the pipe diameter, but in no case need it exceed $\frac{1}{2}$ in. The corners of these holes at the inner surface of the pipe should be free of burrs and slightly rounded.

It is advisable to have the pipes or tubing connecting the pressure holes to the gauges at least $\frac{1}{4}$-in. iron pipe size to reduce the danger of clogging. On the other hand, there is little to be gained by using larger than $\frac{1}{2}$-in. pipe.

The type of instrument to be used for measuring the differential and static pressures will depend to some extent upon the purpose of the measurement. In the past, most orifice meter installations for measuring natural gas have used recording pressure gauges with circular charts, and from the records on these charts the quantity flow through the orifice, for chart period, is computed manually. For some years recording gauges equipped with integrating mechanisms have been used in other industries, but it is only in recent years that these integrators have been used in natural gas measurements. The more advanced of these integrating mechanisms combine and totalize the pressure

factors, and this total multiplied by a meter factor gives the total flow up to that time.

Regardless of the type of recorder used, it is doubtful if any single reading or computation from a single chart record can be relied upon to be correct within less than $\pm 1\%$. Over a series of readings or records, the uncertainty may be less than this.

Equations for Computing the Flow through an Orifice

For convenience in stating the equations for computing the flow through an orifice, as well as the several factors to be used therewith, the following symbols will be used [11]:

D (in.)	= diameter of section. D_1 refers to the average pipe diameter immediately upstream of the orifice. D_2 refers to the orifice diameter.
G (ratio)	= specific gravity, air = 1·00.
g (ft. per sec.^{2})	= gravitational acceleration = 32·174 ft. per sec.^{2}
h_w (in. of water)	= differential pressure across the orifice.
K (ratio)	= discharge coefficient with velocity of approach factor $\left(\frac{1}{\sqrt{(1-\beta^4)}}\right)$ included.
k (ratio)	= ratio of the specific heats of a gas.
p (lb. per in.^{2})	= absolute static pressure; p_1 at the upstream tap; p_2 at the downstream tap.
q (ft.^{3} per hr.)	= volume rate of flow. q_1 at the upstream pressure and temperature; q_c the volume at the base or contract pressure and temperature.
R_d (ratio)	= $\frac{48w}{\pi D_2 \mu}$, the Reynolds number.
T (° F.)	= absolute temperature of the gas = 460 + observed temperature on a Fahrenheit thermometer.
v (ft.^{3} per lb.)	= specific volume.
w (lb. per sec.)	= mass rate of flow.
x (ratio)	= $\frac{p_1-p_2}{p_1}$, the differential pressure ratio.
Y (ratio)	= expansion factor.
β (ratio)	= D_2/D_1 the diameter ratio.
λ (ratio)	= $10^6/R_d$.
ρ (lb. per ft.^{3})	= density; ρ_1 refers to the conditions at the upstream tap, ρ_2 refers to the conditions at the downstream tap, ρ_c refers to the density at the base or contract pressure and temperature.
μ (lb. per ft. sec.)	= viscosity.

The rate of flow may be computed most conveniently by the hydraulic equation. A convenient form of this equation, from which modified forms may be readily deduced, is

$$w = \frac{\pi}{4}\frac{D_2^2}{144} KY_1\sqrt{\{2g144(p_1-p_2)\rho_1\}}, \tag{8}$$

which reduces to

$$w = 0{\cdot}525 D_2^2 KY_1\sqrt{\{(p_1-p_2)\rho_1\}}. \tag{9}$$

The derivation of these equations may be found in textbooks and technical papers on fluid mechanics [11].

Ordinarily, gas quantities are not expressed in terms of mass, but in terms of volume units per hour based on some reference condition of pressure and temperature. (In some cases the relative humidity is also specified.) Also, the pressure difference (p_1-p_2) is generally expressed in terms of the equivalent column of water, h_w. The density, ρ_1, may be expressed in terms of the reference pressure and temperature, the density of air under these conditions, the pressure and temperature of measurement, and the specific gravity of the gas. Making these substitutions in equation (9) and reducing, gives [10; 12]

$$q_c = 218{\cdot}44 D_2^2 KY_1 \frac{T_c}{p_c}\sqrt{\left(\frac{h_w p_1}{GT_1}\right)}, \tag{10}$$

in which p_c and T_c define the reference or contract condition.

Extensive experiments have indicated that, for a given installation, the values of K and Y may be expressed in terms of one or more of four independent variables. These variables are: the pipe diameter, D_1; the diameter ratio, β; the Reynolds number, R_d; and the acoustic ratio, x/k. A discussion of the dependence of K and Y upon these variables may be found elsewhere [10, 11, 12]. It will be sufficient here to give empirical equations by which the values of K and Y may be computed.

Let K_e be the particular value of K when

$$\left.\begin{aligned} R_d &= \frac{10^6 D_2}{15} \\ \text{and therefore} \qquad \lambda_e &= \frac{15}{D_2}. \end{aligned}\right\} \tag{11}$$

Then the value of K corresponding to any other value of R_d is

$$K = \frac{K_e(1+E\lambda)}{(1+E\lambda_e)}. \tag{12}$$

The values of E, K_e, and Y for the three types of taps named above are given by the following equations:

Flange Taps:

$$E = D_2\left(830+\frac{530}{\sqrt{D_1}}-5000\beta+9000\beta^2-4200\beta^3\right), \tag{13}$$

$$\begin{aligned} K_e = {} & 0{\cdot}5993+\frac{0{\cdot}007}{D_1}+\left(0{\cdot}364+\frac{0{\cdot}076}{\sqrt{D_1}}\right)\beta^4+ \\ & +0{\cdot}4\left(1{\cdot}6-\frac{1}{D_1}\right)^5\left[\left(0{\cdot}07+\frac{0{\cdot}5}{D_1}\right)-\beta\right]^{\frac{5}{2}}- \\ & -\left(0{\cdot}009+\frac{0{\cdot}034}{D_1}\right)(0{\cdot}5-\beta)^{\frac{3}{2}}+\left(\frac{65}{D_1^2}+3\right)(\beta-0{\cdot}7)^{\frac{5}{2}}, \end{aligned} \tag{14}$$

$$Y_1 = 1-(0{\cdot}41+0{\cdot}35\beta^4)^{x/k}. \tag{15}$$

Vena Contracta Taps:

$$E = D_2\left(730+\frac{530}{\sqrt{D_1}}-5000\beta+9000\beta^2-4200\beta^3\right), \tag{16}$$

$$\begin{aligned} K_e = {} & 0{\cdot}5973+\frac{0{\cdot}011}{D_1}+\left(0{\cdot}406+\frac{0{\cdot}016}{\sqrt{D_1}}\right)\beta^4+ \\ & +0{\cdot}4\left(1{\cdot}6-\frac{1}{D_1}\right)^5\left[\left(0{\cdot}07+\frac{0{\cdot}5}{D_1}\right)-\beta\right]^{\frac{5}{2}}- \\ & -\left(0{\cdot}009+\frac{0{\cdot}034}{D_1}\right)(0{\cdot}5-\beta)^{\frac{3}{2}}+\left(\frac{35}{D_1^2}+7\right)(\beta-0{\cdot}7)^{\frac{5}{2}}, \end{aligned} \tag{17}$$

$$Y_1 = 1-(0{\cdot}41+0{\cdot}35\beta^4)^{x/k}. \tag{18}$$

Pipe Taps:

$$E = D_2\left(905+\frac{875}{D_1}-5000\beta+9000\beta^2-4200\beta^3\right), \tag{19}$$

$$\begin{aligned} K_e = {} & 0{\cdot}5925+\frac{0{\cdot}182}{D_1}+\left(0{\cdot}440-\frac{0{\cdot}06}{D_1}\right)\beta^2+ \\ & +\left(0{\cdot}925+\frac{0{\cdot}225}{D_1}\right)\beta^5+1{\cdot}35\beta^{14}+\frac{1{\cdot}43}{\sqrt{D_1}}(0{\cdot}25-\beta)^{\frac{5}{2}}, \end{aligned} \tag{20}$$

$$Y_1 = 1-[0{\cdot}333+1{\cdot}145(\beta^2+0{\cdot}7\beta^5+12\beta^{13})]^{x/k}. \tag{21}$$

In each case the expansion factor Y_1 implies that the density is determined by or represented by the absolute static pressure from the upstream pressure tap. If the downstream static pressure is used, then the expansion factor Y_2 is to be used and is given by

$$Y_2 = \sqrt{\left(\frac{p_1}{p_2}\right)} Y_1. \tag{22}$$

Of late some operators have used the mean of the upstream and downstream static pressures to determine or represent the density. The expansion factor, Y_m, corresponding to the mean static pressure is

$$Y_m = \sqrt{\left(\frac{2}{2-x}\right)} Y_1. \tag{23}$$

To use equations like (12) to (21) in routine computations would be inconvenient and slow. This inconvenience may be overcome by computing and plotting a set of curves from which the values of K and Y may be read. Or tables of values of K_e, $(1+E\lambda_e)$, $(1+E\lambda)$, and Y may be prepared for such intervals as will permit reading them with as little interpolation as desired.

In equation (14) the term $(0{\cdot}50-\beta)^{\frac{3}{2}}$ becomes imaginary when $\beta > 0{\cdot}5$ and is then to be treated as if its value were zero. Similar terms in equations (17) and (20) are to be treated in the same way.

It cannot be expected that equations (12) to (21) will yield coefficients that, in all cases, would exactly equal those determined by test. When $D_1 > 1{\cdot}6$ in., the differences between the calculated and test results should not exceed the following amounts within the limits stated for the different pairs of taps: Flange and Vena Contracta Taps:

$\pm 0{\cdot}5\%$ when $0{\cdot}15 < \beta < 0{\cdot}70$

$\pm 1{\cdot}0\%$ when $0{\cdot}10 < \beta < 0{\cdot}15$ and $0{\cdot}70 < \beta < 0{\cdot}75$.

Pipe Taps:

$\pm 0{\cdot}75\%$ when $0{\cdot}20 < \beta < 0{\cdot}67$

$\pm 1{\cdot}50\%$ when $0{\cdot}15 < \beta < 0{\cdot}20$ and $0{\cdot}67 < \beta < 0{\cdot}70$.

The use of calculated coefficients for orifices less than about $\frac{3}{4}$ in. diameter is not recommended. It is very difficult to make two orifices as small as this exactly alike—the imperceptible differences in the edge conditions may cause test results for the two to differ by as much as 2–3%. For this reason, these small orifices should be individually calibrated. To do this with water is relatively easy and does not require extensive equipment.

It may be added that larger orifices may be calibrated also, especially if the importance of the measurement justifies, or there are other reasons making it desirable. Facilities are available for calibrating orifices in pipes as large as 16 in. with either water or gas [2, 3]. It is hardly necessary to add that cost of such a calibration increases with the size.

Venturi Tubes and Flow Nozzles

This article would not be complete without a brief mention of venturi tubes and flow nozzles. However, as these types of differential producers are but little used in commercial measurement of gas, it will not be necessary to describe them in detail. The same installation requirements as given for orifices may be applied to venturis and flow nozzles. For computing the rate of flow through venturis and nozzles, equations similar to (8) and (9) may be used, although, of course, the discharge coefficient values will be different. For most venturi tubes the discharge coefficient with velocity of approach factor *not* included, will usually be between 0·96 and 0·99, depending upon the tube and the rate of flow. The manufacturer of the tube usually furnishes the correct coefficient. For flow nozzles the coefficient values will vary somewhat more widely. In addition to depending on the size and rate of flow, the coefficient value will depend upon the shape of the flow nozzle and the locations of the pressure taps. Because of the variations due to these several factors reference should be made to more extensive papers on flow nozzles for coefficient values [5, 1934; 8; 13, 1928].

(*Note*. An extensive research programme on flow nozzles is being undertaken by the Special Research Committee on Fluid Meters of the A.S.M.E.)

Critical Flow Nozzles and Orifices

The critical flow orifice, or rather nozzle, is frequently used as a reference meter with which to test large displacement gas meters *in situ*, and as a control for regulating the rate of flow into a gas line. The equations used in computing the rate of flow through these meters are developed from the fact, theoretically indicated and experimentally observed, that the mass rate of flow through a short nozzle or orifice of well-rounded approach increases as the outlet pressure is decreased until this pressure is about half of the inlet pressure. After this point is reached further decreasing of the outlet pressure does not cause any further increase in the mass rate of flow. The ratio of the outlet to inlet pressure at which this maximum rate of flow is obtained is termed the 'critical' pressure ratio, r_c. The value of this critical pressure ratio may be computed by calculus from the adiabatic equation for the mass rate of flow. (This equation may be found in more extended articles [11].) It should be noted that experiments have indicated that the relations for the maximum rate of flow through round-edged orifices or nozzles do not hold with square-edged orifices, and that with the latter the discharge continues to increase as the pressure ratio is decreased below the critical value.

Using the symbols given above, the maximum rate of flow in terms of the upstream conditions is given by

$$q_1 = \frac{\pi D_2^2}{48} C \sqrt{\left\{g \frac{p_1}{\rho_1} k \left(\frac{2}{k+1}\right)^{\left(\frac{k+1}{k-1}\right)}\right\}}, \tag{24}$$

in which q_1 is in cu. ft. per sec. and C is an experimentally determined coefficient for each orifice.

Using the relation for an ideal gas or

$$\frac{p_1}{\rho_1} = \frac{R_a T_1}{G}, \tag{25}$$

in which R_a is the 'gas constant' for air, equation (24) becomes

$$q_1 = \frac{\pi D_2^2}{48} C \sqrt{\left\{g \frac{R_a T_1}{G} k \left(\frac{2}{k+1}\right)^{\left(\frac{k+1}{k-1}\right)}\right\}}. \tag{26}$$

The value of R_a for air is 10·73 ft. lb. per lb. mol. per °F., and this may be combined with g and $\pi/48$ to give a single numerical factor.

When used for testing other meters the critical flow orifice or 'prover' is (usually) attached to the outlet of the meter under test and a pressure drop of over 50% of the inlet pressure maintained across it. The procedure is then to determine the time in seconds required for 1 cu. ft. of gas at the inlet conditions to pass through the meter under test, and to compare this with the time that theoretically

should be required, as calculated from the calibration of the critical flow prover. Let

t_a (sec.) = air time as given by the prover,
t'_g (sec.) = the calculated gas time,
t_g (sec.) = the observed gas time,
k_a, k_g = specific heat ratios for air and gas respectively,
T_s (° F. abs.) = standard or reference temperature,
T_1 (° F. abs.) = observed inlet temperature at time of use.

Then

$$t'_g = t_a\sqrt{\left(\frac{GT_s k_a}{T_1 k_g}\right)} \tag{27}$$

and

$$\frac{\frac{1}{t_a}-\frac{1}{t'_g}}{\frac{1}{t'_g}}100 = \text{meter proof or per cent. error of the meter under test.} \tag{28}$$

It should be noted that equation (27) is an empirical equation, but it is sufficiently exact for all ordinary uses. For the corresponding theoretical equation and the development of other equations given in this section, reference should be made to more extensive papers on the subject [11].

The Pitot Tube

In its simplest form the pitot or impact tube is a small-bore tube bent near one end at right angles. In use, the tube is held so that the short end opens or faces into the stream, the flow of which is to be measured. The other end of the tube is connected to a manometer or some other type of pressure gauge. When used to measure the flow in a closed channel an additional connexion must be employed from which the static pressure and hence the density is determined. This static opening may be combined with the impact tube, or it may be a pressure side hole in the wall of the pipe [4, 1915; 11]. If carefully used, pitot-tube indications may be relied upon to within 1–2%: however, the pitot tube is more often used where an accuracy of 5–10% is sufficient.

The pitot tube is strictly a velocity indicating instrument, and the development of the equation for the stream velocity is similar to that for the orifice. The equation for the stream velocity at the position of the impact tip is

$$V\text{ (ft. per sec.)} = \sqrt{\left(2g\cdot\frac{62\cdot 34}{12}\frac{h_w}{\rho}\right)}, \tag{29}$$

where h_w (in H_2O) = the impact head,
ρ (lb. per ft.^{3}) = density of the gas at the section of measurement.

The velocity coefficient of the pitot tube is unity.

The volume rate of flow of the stream is

$$q\text{ (ft.}^3\text{ per sec.)} = ACV$$
$$= AC\sqrt{\left(10\cdot 4g\frac{h_w}{\rho}\right)}, \tag{30}$$

in which

A (ft.^{2}) = area of the stream,
C (ratio) = ratio between the average velocity over the section and the velocity at the position of the impact tip.

The value of C may be determined from a traverse of the stream, and this should be done if more than approximate measurements are desired. For approximate measurements the impact tip may be placed at the centre of the pipe, and the value of C taken as $0\cdot 83 \pm 0\cdot 05$. Or, the impact tip may be placed at about one-eighth the pipe diameter in from the pipe wall, and the value of C taken as 1·00. Both of these two procedures are subject to more or less uncertainty since the relative distribution of velocities over stream sections varies widely.

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CALIBRATION OF TANKS

By A. W. COX, F.C.S., M.Inst.P.T.

THE word 'calibration' is used to denote the process of obtaining the necessary information in regard to receptacles for holding liquids which will enable tables to be drawn up showing their capacity at various heights. The tables so prepared are called 'calibration tables' or 'calibration scales'.

Information for the purpose desired may be obtained in several ways. The principal methods are, by measurement, by water, and from builders' plans.

Calibration by Measurement

Calibration may be carried out by internal or by external measurement. The principles underlying both methods are the same for all receptacles, but details vary according to their sizes and shapes.

The steel tapes used in calibration by measurement in this country and in America are accurate at 68° F. when under a tension of 10 lb. Theoretically, therefore, calibrations should be carried out at 68° F., but this is of course impracticable. The error introduced by calibration at other temperatures depends on the difference between the average temperatures of the tank and the tape at the time of calibration, and also on the difference between the coefficients of expansion of the tape and of the tank. These errors are generally small, and it is not customary to attempt to correct for them.

1. Vertical Cylindrical Tanks (Fixed Roof).

(*a*) **Strapping.** This method is normal practice in America and is also occasionally used in this country. The word 'strap' is used to denote the measurement of outside circumferences by stretching a steel tape round the outside of the tank.

In this country the strapping method has to be used in the cases of tanks which already contain liquid. In such cases measurements of internal fittings and displacements cannot be taken, and allowance for them can only be made from builders' plans.

The strapping of a tank is carried out when it is full of liquid, the tape being stretched round the tank at various places. The American Petroleum Institute [1] requires that the measurements are made at the bottom of each tier, and at the top of the top tier, in the cases of tanks of 'shingled' and of 'in-and-out' construction. Welded tanks are required to be measured at 2 ft. from the bottom of the tank and thence every 4 ft. upwards. Vertically flanged tanks are strapped by using calipers to span the flanges and taking measurements of length from each caliper leg.

The heights of the tiers are taken at two points on each tier, and the thicknesses of the plates are obtained with a depth gauge. The amounts of the overlaps of the plates are also determined.

Measurements are taken to the nearest one-tenth of an inch. (American recommended practice is to use tapes graduated in hundredths of a foot and to take measurements to the nearest one-hundredth of a foot.) The average internal diameter of each tier is obtained by calculation from the circumference measurements, due allowance being made for the thickness of the plates.

(*b*) **Internal Diameters.** The tank is filled to its capacity with water, and is then emptied. Measurements of diameters are taken inside the tank by means of a steel tape. The diameters of tanks which have an even number of plates in each tier are taken at predetermined positions on a diagonal on each plate to corresponding positions on the opposite side of the tank.

In the cases of tanks in which the tiers are composed of odd numbers of plates, diameters are measured at top, middle, and bottom positions on both sides of the vertical laps, to corresponding positions on the opposite sides.

In order to avoid having to correct for the stretch and to determine that the tension is that at which the tape is standard, a dynamometer is employed. A satisfactory type (Fig. 1) consists of the combination of a flat plate fitted with a spring balance, to which a steel tape can be attached. A pin is provided to move with the balance spring so that it engages a suitable electrical contact, which operates a buzzer or a light. The use of a dynamometer ensures that accurate correction for sag can be made for each diameter measurement which is taken.

The dynamometer is held against the side of the tank at one end of the tape, and the other end of the tape is pulled by a second operator until the required tension is obtained. In the case of the dynamometer described it is previously adjusted so that when the desired tension is reached the buzzer sounds or the light shines. The exact measurement of diameter is then read off the tape by the use of a stiff wooden rule which is held, together with the tape, at the point on the side of the tank which is directly opposite the one at which the dynamometer is being held.

The diameter of each tier is calculated by averaging the figures obtained on all the plates of each tier. The error due to the sag of the tape used is calculated and allowed for.

Measurements are taken of all angle irons, stanchions, brackets, supports, gussets, or other internal fittings (the so-called 'deadwood' of the tank), and of the heights from the floor at which the fixtures occur. These measurements are made so that the volume occupied by the fittings can be calculated.

2. Vertical Cylindrical Tanks (Floating Roof).

The shells of these tanks are calibrated as in the case of fixed roof tanks. The floating roof, with all attachments which move under it, is measured to determine the deadweight. In the case of a pontoon roof measurements are also made of the underside of the pontoons which support the roof. The displacement of the roof at various heights up to the point of incipient floatation can then be calculated as deadwood, and deducted from the capacity of the shell of the tank at the height at which the displacement occurs.

The determination of the displacement of a floating roof by running into the tank measured quantities of water from a small calibrated tank is found to be subject to more serious errors and anomalies than occur when a roof is calibrated by measurement and deadweight. The method is also a lengthy one, as it is essential that after the running in of each quantity of water, sufficient time is allowed for the floating roof to assume its correct position and for the water to settle to a smooth surface in both tanks before

measurements of depths can be taken. The friction of the 'shoes' on the shell of the tank, the irregular movements of the roof plating as liquid rises in the tank, and the uneven distribution of weight over the roof, all make calibration of floating roofs by water an unsatisfactory method.

It is recognized by the American Petroleum Institute [1] that the displacement of the immersed part of the roof of a floating-roof tank cannot be obtained very accurately, and the Institute recommends that the part of the Calibration Table 'over which the deck deadwood is distributed, including an inch or so above and below', should be marked 'Not accurate'.

The point of incipient floatation of a roof will vary according to the density of the liquid in which it floats. This fact makes the preparation of a calibration table for these tanks a matter of some difficulty and complication. In order to render the matter as simple as possible it is customary to calculate allowances for a floating roof according to the density of the liquid which is to be stored in the tank. A calibration scale thus prepared is only accurate when liquids which have densities between a given range are measured, and the range of densities allowed is calculated so that the maximum error incurred is slightly less than the personal errors in 'dipping'.

3. Cylinders (horizontal).

The calibration of cylinders which are fixed in a perfectly horizontal position is carried out in a similar manner to that of vertical tanks, either by the strapping or internal diameters method.

In the case of the strapping method measurements of the circumference are taken on each strake, in order to obtain the average circumference of the cylinder. The average internal diameter is then calculated, due allowance being made for the thickness of the plates. Record is made as to whether the dipholes provided are over inside or outside strakes.

The lengths of flat-ended cylinders are measured in several places so as to obtain an average figure. In the case of round-ended cylinders the curves of the ends must be measured, so that the necessary calculations of capacity can be made. This can be accomplished by holding a plumb-line so that it just touches the bulge of the end, and then taking measurements of distance from this line to the end of the cylindrical portion of the tank at various heights from the top and bottom.

Calibration by internal diameters is made by measuring diameters on each plate and lengths at several heights from the floor. It presents no special difficulties if the cylinder has flat ends. In the case of round-ended cylinders further measurements are taken in order to calculate the capacities of the ends. A fixed vertical line is obtained inside the tank at the end of the cylindrical portion of the cylinder. From this line horizontal measurements to the rounded end are taken at various intervals, according to the size of the tank. This operation is carried out at both ends of the cylinder, the distance between the vertical lines at each end then constituting the length of the cylindrical portion.

Calculations of the capacity of a horizontal cylinder are made separately for each inch in height as, of course, no two inches have the same volume.

4. Square and Rectangular Tanks.

The calibration of these tanks is carried out by inside or outside measurements, in a manner similar to that of vertical cylindrical tanks, the number of measurements taken depending on the size of the tank and the number of plates. Interior stiffening rods, angle irons, and other fittings are measured, and the positions in which they occur are noted.

It will be realized that unless square and rectangular tanks are built of plates of substantial thickness, and are well braced, accurate calibration may not be possible owing to irregularities which may occur in the plates when the tank contains liquid. In some cases calibration may be more accurately carried out by water.

5. Barges and Small Tank Vessels.

Calibration by measurement of barges which contain rectangular tanks is carried out as in the case of other square or rectangular tanks. The number of measurements taken is decided according to the circumstances of the case, the object being to take sufficient of them to obtain accurate average dimensions. It is customary to set the tanks in a tank barge so that there is a slope on the floor towards the suction-pipe or sump, and the necessary observations are made so that capacities can be calculated in relation to heights taken at the dipping places. Templates are taken of rounded corners so that scale drawings may be made for the determination of the capacities of these parts.

Calibration by measurement of barges and small tank vessels in which the hull of the vessel constitutes the tanks is a more complicated matter, owing to the curves and slopes of the sides and bottom, but the same general principles hold good as for other receptacles. Barges and tank vessels must be on even keel when they are calibrated.

Calculation of Capacities

The calculation of cubical capacity of the shells of receptacles from the measurements obtained in calibration is made by normal mathematical procedure. The volumes of displacements and additions are also calculated, and are allowed for in the figures of shell capacity at the positions they occupy in the receptacle. The actual cubical capacity of the receptacle is thus obtained, and from these figures the volumes in the required unit are obtained. In this country the volume unit used is the Imperial Gallon. A table is then prepared showing the volume at each unit of height desired, usually at each inch from the floor.

The most authoritative series of conversion factors, both of volume and weight, is that published by the Institution of Petroleum Technologists [2].

A source of error which cannot accurately be allowed for occurs in vertical cylindrical tanks which are not built on good foundations. In such cases the floor may become uneven in various places and the unevenness may vary with differing weights of liquid. It is possible for a large quantity of liquid to be concealed in a floor which becomes dished. The use of a datum line is to be deprecated unless it can be proved that the formation of the floor never alters.

Calibration of an uneven floor is sometimes carried out by running a quantity of liquid from an accurately calibrated tank into the tank in question until all irregularities are covered, and then measuring the quantity which has been transferred. This can only be considered as a compromise.

Calibration by Water

Calibration by water is carried out by running measured quantities of water either into or out of the vessel which is being calibrated, and taking measurements of the depths of water at each increment or decrement. Owing to its

FIG. 1 Dynamometer

lengthy nature it is seldom used for large receptacles, but it is the best way of calibrating many irregularly shaped and sloping receptacles.

1. Bottoms of Large Tanks.

The method can be used to ascertain the capacity of an uneven floor. The figures obtained may not always truly represent the quantity of liquid contained when the tank is in use, owing to alterations in the formation of the floor, but the method is useful in cases of tanks in which the bottoms cannot be kept water-flooded.

The tank to be measured is connected by pipeline with another accurately calibrated tank. Water is then run by gravity from the calibrated tank until the floor is covered. Dips of both tanks are taken when the surface of the water is perfectly still and, by reference to the calibration table of the calibrated tank, the amount of water held by the floor of the tank is obtained. This figure can then be regarded as a constant, at the dips observed.

2. Cylinders and Tank Wagons.

Measures of accurately known capacity are used in the calibration of small cylinders, tank wagons, and similar receptacles. A convenient type is the 'Strike' measure, and usual sizes are 1 gallon and 5 gallons. The measures are standardized for their filled capacity. They cannot be considered as absolutely accurate for delivered quantities, owing to the varying amounts of liquid which adhere to the sides when they are emptied.

The receptacle to be calibrated is filled with water and a measurement of height of liquid taken. A quantity of 5 gallons is run out into the measure, and another measurement of height is taken. The measure is dried out and the process repeated until less than 5 gallons remain in the receptacle. The remaining quantity is run out into a standard 1-gallon measure in a similar manner, and finally into standard glass measures of convenient capacity. In this way the data is obtained to enable a calibration table or a dipstick to be prepared showing the volumes for various heights. Small cylinders which are not set horizontally, sloping tank-wagons, or small irregularly shaped receptacles are calibrated most accurately by the water method. All measurements of heights of liquid must be made at the point at which dipping will be carried out when the vessel is in use, and the calibration table or dipstick prepared must be understood to be accurate only if the position of the vessel remains unaltered.

The capacities of the measures used in calibrating by water depend on temperatures, and it is necessary to calculate the actual volume by the use of the cubical expansion of the metal of which the measures are made.

The temperature of the water in the receptacle which is being calibrated must be known, but no allowance need be made for alterations in temperature which are only of a few degrees. When water-calibration work extends over several days it may be necessary to adjust the depth of water in the tank at the commencement of each day, in order to correct for evaporation or change of temperature.

3. Barge and Ship Tanks.

The calibration of the cargo tanks of barges or small ships is sometimes carried out by water. The method is particularly useful where the skin of the vessel constitutes the tanks, such tanks being difficult to calibrate by measurement owing to the slopes and curves on the bottom and sides, and the large amount of internal displacements.

The vessel to be calibrated is placed on an even keel. A tank of suitable size (generally about 40 gallons), or a barrel-filler, is calibrated by standard measures, due allowance being made for the temperature of the measures. Successive quantities of water are run in from the calibrated tank and measurements of height in the barge tanks are made at each addition. The temperature of the water in the calibrated tank and in the barge tanks is taken at convenient intervals in order to ensure that it does not vary by more than a few degrees from the temperature at which the small tank was calibrated. The measurements of depth in the barge tanks are made at the centres of the tanks, and the calibration tables prepared can only be considered as accurate when dips or ullages are taken at the same points in the tanks, and when the vessel is on an even keel.

4. Conical Bottoms of Cylinders.

The calibration by water of the conical bottoms of vertical cylindrical tanks is carried out as described for other receptacles. The choice of calibrated strike measures, barrel-fillers, or small tanks is made according to the size of the cone. Measurement of depth must be made at the position at which the cylinder is to be dipped when in use. The calibration by measurement of the cylindrical part of the tank commences at the level at which the water used for the cone finishes.

MEASUREMENT OF OIL IN BULK

(*a*) Dips.

The word 'dipping' is used to denote the determination of the height of liquid in a receptacle by means of instruments which will reach to the bottom of the vessel in which the liquid is being measured.

The usual instruments used for the purpose are steel tapes to which are attached weights of definite length. The tape used is one of convenient length, and is usually graduated in feet, inches, and tenths of 1 in. A convenient width for the tape is half an inch, and a usual thickness eight-thousandths of an inch. Each tape is fitted with a steel ring at one end in which the weights used are held fast by a clip which is fitted to them. In some cases tapes are graduated so as to allow for the length of the weight, but tapes are also used in which the zero graduation is at the end of the ring. In the latter case it is necessary to add the length of the weight to the measurement recorded on the tape. This type of tape has the advantage that weights of any length, or ullage rules, can be used, whereas the other kind of tape requires to be used only with a weight of a definite length.

The weights used in dipping must be of definite length and of sufficient weight to fall freely through the liquid which is being measured, so that the tape attached to it may be drawn taut in a perfectly vertical position. In this way a definite mark is left on the tape at the height of the surface of the liquid, and an accurate measurement of depth is obtained. A slight error is introduced when measuring liquids which are at abnormally high or low temperatures, owing to the expansion or contraction of the tape. Steel tapes are usually standard at 68° F., and the error introduced by using such a tape at other temperatures will amount to 0·002 in. for 1° F. in a length of 30 ft. This is smaller for the range of temperatures usually encountered in measuring oils in bulk than the usual possible errors in dipping, and is ignored in practice.

Dip rods are sometimes used instead of tapes and weights for small vessels such as horizontal cylinders and tank wagons. These may be graduated in feet, inches, and tenths of 1 in., or may be specially graduated in gallons for a particular tank. They are subject to errors due to the difficulty of ensuring that the rod is held in an upright position when measurements are made.

Large vertical cylindrical tanks are usually provided with a number of places on the roof from which dips can be taken. This is necessary because of irregularities in the levels of the floors. Such variations may be only small ones due to riveting of plates to form the floor, or they may be larger, due to alterations in the formation of the floor or movements of the tank.

The usual number of places for dipping is 5, 1 being in the centre and the other 4 at the sides of the tank near the ends of two diameters which are at right angles. In these cases the average height of liquid is obtained by averaging the centre dip with an average of the 4 side dips. Very large tanks, such as those with diameters of over 100 ft., should be dipped at not less than 9 places, the extra 4 places being midway between the centre and the outer positions. In these cases the average of the 9 dips is taken as the height of the liquid.

When measurement is being made of a quantity of liquid which is being pumped into or out of a tank, the averaging of dips will minimize errors due to changes in the formation of the floor, provided the floor is covered with liquid before pumping into or after pumping out of the tank.

Errors due to uneven and changing tank floors are accentuated when taking the stock contained in a tank, when measuring a delivery which entails emptying a tank, or when filling a tank which is empty at the commencement. These errors can be avoided with mobile liquids which do not emulsify with or become spoiled by contact with water, by keeping the floor of the tank flooded with water. In this way a level surface of oil is formed at the oil-water interface in the cylindrical part of the tank, and accurate measurements are made possible.

(*b*) Ullages.

The determination of the quantity of liquid in a tank may be made by measuring the distance from the top of the tank to the surface of the liquid. Such measurements are termed 'ullages'. They are used in the cases of land tanks where obstructions render dipping impossible, and where tanks contain solid or viscous substances at the bottom which prevent a tape and weight from reaching the floor in a vertical position.

Ullages are taken with a steel tape to which is attached an ullage rule. A convenient form of the latter consists of a graduated metal rule 1 ft. in length, in which is inserted a strip of ebony. The rule has a fitting at one end for fixing to the ring of the tape, and is graduated so that the ullage rule reading is added to the reading on the tape.

Measurement of quantities by ullages presupposes that fixed points are available on the tanks from which ullages can be taken, and that the total heights from the floor to these fixed points remain constant. The possibility of alterations in the floors of tanks makes it necessary that opportunities should be taken whenever possible to check total heights. The depth of liquid is obtained by deducting the ullage measurements from the total heights at the respective positions at which the ullages were taken.

The calibration scales of ships tanks are usually based on ullages taken from plug-holes in the lids of the tanks. Plug-holes should be fitted at points midway between the forward and after bulkheads of each tank, in order that measured quantities may not be seriously affected by the trim of the ship. Where this is not possible two plug-holes should be fitted at points equidistant from the transverse bulkheads [4].

(*c*) Temperature.

The volume of a liquid varies with its temperature, and it is therefore necessary to know the temperatures of liquids which are being measured in bulk. For this purpose samples are taken at various depths in the tanks. A suitable weighted container is lowered to the required depth, allowed to remain for sufficient time to assume the temperature of the liquid, allowed to fill with the liquid, and then rapidly raised to the top of the tank, where the temperature of the liquid is taken. The usual practice is to take samples at equal intervals so that they represent the top, middle, and bottom thirds of the liquid contained in the tank. This applies particularly to mobile liquids and to liquids which are not artificially heated.

It may be necessary in some cases, such as where liquids are artificially heated, to take a larger number of samples in order to obtain the average temperature of the whole contents of the tank.

The temperature of liquid in a horizontal cylinder is usually taken as that of a sample drawn from the centre of the liquid. When further temperatures are required it must be remembered that the quantity of liquid represented by a sample varies with the positions at which it is taken.

The American Petroleum Institute, in their Code for Crude Oil [1], recommend the use of a cup thermometer for the taking of temperatures. This method cannot be considered accurate where large quantities of liquid are involved, particularly when the liquid is artificially heated.

(*d*) Water.

Oils which are being measured in bulk must be searched for the presence of free water lying at the bottom of the tank, otherwise false measurements of the depth of oil will be obtained. The determination of the depth of water is made by the use of materials which are acted upon by water but which are unaffected by oil or spirit. A usual method is to lower to the bottom of the tank a specially prepared paper which is covered on one side with a brown preparation. The latter is soluble in water, and, on removal of the paper, a clear indication of the depth of water is shown by the height to which the brown colour has been removed. A quicker preparation is a brown paste which loses its colour when it comes into contact with water. It is placed in a thin layer on a rod or weight, and, when used in spirit, a few seconds are sufficient to obtain a definite measurement of the depth of water. Other materials used are blue chalk and a blue paste, both of which lose their colour when immersed in water. Measurements of the depth of water in a tank are usually taken at the points at which the smallest and the largest dips were obtained.

It will be observed that if the floor of a tank is completely covered with water, the height of the oil at each diphole, obtained by deducting the depth of water at each diphole from the total height of liquid at the respective diphole, should be identical.

(*e*) Pipelines.

It is necessary to consider the condition and capacities of pipelines when measuring quantities of liquid which are transferred from one receptacle to another. These lines are of various diameters and may be of considerable length, and, if precautions are not taken, large quantities of liquid may be concealed or delivered without being measured. When dealing with mobile oils or spirits, pipeline errors can be avoided by pumping water into the line after the transfer has been made and then blowing the water into the tank by the use of compressed air. In some cases pipelines are maintained full of liquid before and after transfer, while in other cases compressed air is blown through the line to clear it. These two methods are less satisfactory as it is not generally possible to determine the amount of liquid which is left in a pipeline.

The capacities of full pipelines are obtained by calculation from measurements of their lengths and diameters.

(*f*) Calculation of Quantities.

(i) **Volume.** The volume of liquid measured in a receptacle is obtained from the dips or ullages by reference to the calibration scales of the vessel concerned. The volumes are usually shown in imperial gallons, but if, as in the case of most tank vessels, the figures are given in cubic units they can be converted to gallons by the appropriate factor [2].

Volumes thus obtained are accurate only at the temperature of measurement. Conversion to volume at a different temperature may be carried out by the use of specific gravities or by means of coefficients of expansion.

Coefficients of expansion of liquids measured in bulk vary considerably according to the composition of the liquid. Tables of coefficients of expansion of oils and spirits derived from one crude oil can be prepared with accuracy, but these figures do not necessarily apply to products obtained from other sources, even if they are of similar specific gravity or boiling-point.

The American Bureau of Standards [3] publishes tables giving corrections in volume for liquids of varying specific gravities. These tables are useful as a guide, but are not accurate for all products of the specific gravities mentioned.

The proposal was made at the World Petroleum Congress in 1933 [5] that liquid products should be dealt with entirely on the basis of volume, but the difficulties involved, such as differing coefficients of expansion, make it probable that calculations of alterations in volume with changes in temperature will continue to be made by the use of specific gravities. This is carried out by multiplying the measured quantity by the specific gravity at the temperature of measurement and dividing the resulting product by the specific gravity at the temperature at which the gallonage is required.

(ii) **Weight.** The conversion of volume in gallons to weight in pounds depends on the Statutory definition of the Imperial Gallon, which is defined as 'Containing ten Imperial Standard Pounds weight of distilled water, weighed in air against brass weights, with the water and the air at a temperature of sixty-two degrees of Fahrenheit's thermometer, and with the barometer at thirty inches' [9].

It is customary in bulk-oil transactions to take 60° F. as the standard temperature, instead of 62° F. as laid down in the Weights and Measures Act, and the practice is, therefore, to compare weights of oil with corresponding weights of distilled water at 60° F. The calculation of the weight of a measured volume of liquid is in consequence carried out by multiplying the measured gallons by 10 times the specific gravity at the temperature of measurement ($S^{t^\circ \mathrm{F.}}/60^\circ$ F.). The resulting figure is weight in Imperial Pounds.

The determination of specific gravity may be made by hydrometer or pycnometer, but, especially when dealing with large volumes, the latter method is recommended, as by its use specific gravities accurate to 4 places of decimals can be more readily obtained.

(iii) **Delivered Quantities.** The measurement of quantities transferred into or out of land tanks is carried out by taking dips or ullages, temperatures, water-depths, and specific gravities of the liquid contained in the tanks before and after the transfer. Each volume measured is converted into weight and the difference between them represents the quantity transferred.

(*g*) Sampling.

The accurate sampling of bulk liquids is a matter of great importance. The calculation of weights of bulk liquids depends on the samples used for determination of specific gravities, while the testing of samples for quality is valueless unless the samples are truly what they purport to be.

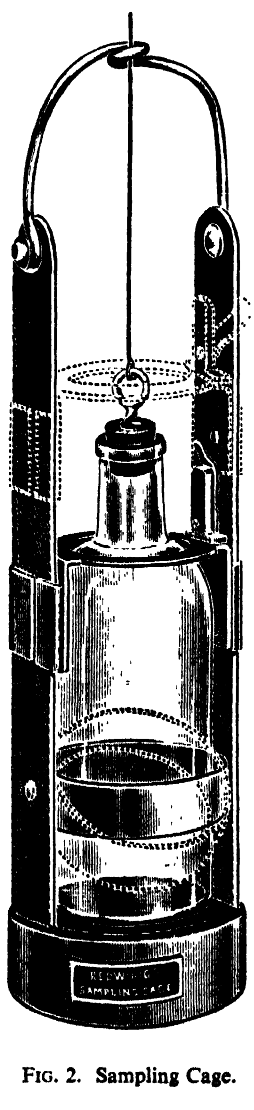

FIG. 2. Sampling Cage.

The Institution of Petroleum Technologists and the American Society for Testing Materials give useful guides for sampling [6, 7], but no set of rules can cover the different circumstances which are encountered in practice.

Sampling of liquids in bulk is usually carried out with a weighted bottle or a weighted cage which holds a bottle (Fig. 2). In each case the bottle is fitted with a cork which can be released when the bottle reaches the point where it is desired to take a sample.

Samples from vertical cylindrical tanks are usually taken from the middle points of zones which represent top, middle, and bottom thirds of the liquid in the tank. This is not always sufficient, as it is possible to have layers of different densities in bulk liquids which are mixtures. The procedure in those cases is to take samples at more frequent intervals and from several positions in the roof of the tank. The samples thus obtained are then mixed to obtain an average sample. The sampling of viscous liquids at a number of depths is often essential, as such liquids do not mix readily when pumped into tanks already containing other oil.

Sampling must be carried out without contamination. One way of doing this is to use a weighted cage into which clean bottles can

be placed for each sample. In this way contamination from the sampling vessel can be avoided, and also losses due to pouring from one vessel to another.

The sampling of heterogeneous liquids in horizontal cylinders must be carried out with due regard to the different quantities represented at various positions in the cylinders. The American Society for Testing Materials standard method [6] requires that samples from the top, middle, and bottom of full cylinders are taken in the ratio 1:8:1. The proportions of samples to be taken from cylinders which are not full must be decided by circumstances. The Standardization of Tar Products Tests Committee recommend the sampling of full cylinders at four depths, the two middle samples being twice as large as the upper and lower ones [8].

Running, or all levels, samples are sometimes taken from vertical cylindrical tanks. A bottle is lowered to the lowest depth at which it is required to sample, the cork is removed, and the bottle gradually and regularly raised so that when it reaches the top of the liquid it is almost, but not quite, full. The method cannot give a truly representative sample even if the operator is able to raise the bottle at a uniform speed, owing to the difference in the quantity of liquid which will flow into the bottle under the varying pressures which occur as the bottle is raised.

The sampling of liquid which is being transferred from one receptacle to another is sometimes carried out by taking samples from the pipeline through which the liquid is being delivered. A small pipe is inserted in the pipeline and the liquid is either allowed to drip continuously during the transfer, or small samples are run off at convenient intervals. Rates of pumping, rate of passage of liquid over the whole cross-section of the pipeline, air locks, solid materials, and free water, all render this method of sampling somewhat speculative.

When one small pipe is used it is placed in the pipeline so that the opening of the pipe is in the centre of the pipeline, facing the direction of flow of the liquid [8]. A more carefully regulated method is that laid down by the American Society for Testing Materials, in which three pipes are inserted in the pipeline, one at the centre and the other two at equal distances from the centre to the side of the pipeline. The diameters of the openings in the pipes are varied according to their positions, the centre one being 0·30, the first from the centre 0·15, and the one nearest the side 0·05 times the diameter of the pipeline. Pipeline sampling methods are liable to inaccuracies due to particles of solid or semi-solid materials partially or completely choking the openings in the sampling pipes.

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SECTION 15

CRUDE OIL TRANSPORT

THE LAWS OF FLUID FLOW IN PIPELINES

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Introduction

THE flow of fluids in pipelines is a subject which, however it is dealt with, comes finally to the purely practical problem of calculating a rate of flow, a pressure drop, or a pipe diameter, given all the other conditions.

Now it might be thought that the provision of a complete set of working formulae is all that is needed to deal with all practical cases (as might be said to be the case with water), but the range of conditions which have to be dealt with by the refinery engineer is so great that it is essential that he should have a thorough grasp of the basic principles if he is to deal successfully with any but the most straightforward cases.

For this reason the course has been adopted in this article of briefly describing the various physical conditions which occur when a liquid flows in a pipe; next describing the methods which can be used to reduce these conditions to a state of order suitable for being used as the basis for methods of calculation, and finally giving equations for practical use.

The Possible Conditions of Flow

Experiment has shown that the flow of a fluid in a pipe may fall into any one of three divisions:

(*a*) Stream-line flow.
(*b*) Turbulent flow.
(*c*) Flow in the critical region.

These types of flow apply to 'true' liquids and gases, i.e. those obeying Newton's Law, possessing no structure, and exhibiting a constant viscosity independent of the rate of shear. The behaviour of liquids not obeying this law is discussed in articles [39, 41, 42].

The first of these, Stream-line Flow, is also known as Viscous or Laminar Flow, or Orderly Motion, and, as its names imply, consists of a type of flow in which each particle of the fluid pursues a smooth path parallel to the walls of the pipe and the path of one particle does not at any point cross the path of another. This type of motion is found to take place at low velocities, and particularly in small pipes with viscous liquids.

The most important feature for purposes of calculation is that in this case the pressure drop in any given pipe system is proportional to the rate of flow, and the only property of the fluid on which it depends is the absolute viscosity. The laws governing this type of flow were first thoroughly investigated by Poiseuille in his classical research [24, 1842] on flow in capillary tubes.

The second type, Turbulent Flow, is known alternatively as Hydraulic Flow or Eddying Motion, and here the body of the fluid consists of a mass of eddies which are thrown off the walls. The circular motion of the eddies, superimposed on the forward motion of the fluid as a whole, combines to give paths to the fluid particles which lie at all sorts of small angles to the walls of the pipe. This type of motion occurs at high velocities and particularly with non-viscous fluids and in large-diameter pipes.

The pressure drop in this case is nearly proportional to the square of the rate of flow and depends primarily on the density of the fluid, and only to a minor extent on the viscosity. The influence of viscosity may be said to affect the result only in so far as it modifies the eddies, and at very high velocities, as will be seen later, its influence becomes very small.

The flow of water is almost invariably of this type, and this has been the subject of innumerable investigations, beginning with D'Arcy's [7, 1858] work on the flow in the water-mains of Paris, and as an exaggerated illustration of how little the viscosity of the fluid matters it may be pointed out that none of the early investigators took any notice of it at all.

The Critical Region lies intermediate between the states of stream-line and turbulent flow, and consists, in fact, of a succession of changes from one type of motion to the other.

When this takes place the pressure drop varies as a power of the rate of flow higher than the square, and the conditions are more complicated than in either of the previous cases.

The Reynolds Number

We now come to the consideration of the factors which determine what type of flow will take place in any given case. It is logical to suppose that the condition of flow will be governed by a combination of some or all of the relevant physical properties of the fluid and of the pipe. Dimensional analysis first applied to this problem by Lord Rayleigh [26, 1892] points to the group $vD\rho/\eta$ or vD/ν as being the factor of major importance, and experiment confirms this. In these expressions v is the mean velocity of the fluid in the pipe, D the diameter; η is the absolute viscosity and ρ the density of the fluid. The two expressions are exactly equivalent. In the first the Absolute Viscosity, η (dimensions M/LT), is used, and in the second the Kinematic Viscosity, ν (dimensions L^2/T) is written in place of η/ρ. Osborn Reynolds [27, 1883] showed, by experiments on pressure drop and by visual examination, that whether flow will be turbulent or stream-line in any particular case depends solely on the numerical value of this function: if $vD\rho/\eta$ is above 3,000, the flow will be turbulent, if below 1,000, stream-line, while at intermediate values there is the region of intermittent turbulence referred to above. Since this region, between $vD\rho/\eta = 1{,}000$ and 3,000, marks the change from the one type of flow to the other, it has been called the critical region.

The group $vD\rho/\eta$ has been called the Reynoids Criterion, or Reynolds Number, after its discoverer, and will be denoted R_e in this article, a symbol which has been given wide acceptance. As will be seen later, it is the basis of half the general problem of fluid flow (by far the most important half to the practical engineer), and it has come to be of paramount importance in such problems as heat transfer and mass transfer. It is therefore necessary to consider it in detail, and we shall first examine the use which has been made of it in placing turbulent flow and flow in the critical region on a sound basis.

The Reynolds Number and Dynamic Similarity

With the exception of the early work of Poiseuille, which was entirely confined to viscous flow in tubes of capillary

dimensions, it may be said that the work of Reynolds was the first attempt to put the subject of flow in pipes on a satisfactory scientific basis.

Reynolds investigated the subject in two ways: by measuring the pressure drop along a straight length of pipe and plotting this against the velocity on a logarithmic scale, when, as the motion changed from one type to another, there was a sharp change of direction in the line; and also by observing the behaviour of a stream of coloured liquid injected along the axis of a tube when the occurrence of turbulence caused the coloured liquid to become mixed with the bulk of the liquid owing to the formation of eddies.

In this way Reynolds showed that the 'critical' velocity at which stream-line flow gave way to turbulent flow was defined by the Reynolds number reaching approximately 2,000 in all cases.

The investigation was taken up by Stanton and Pannell [33, 1914], who made very careful measurements of the pressure drop in smooth-drawn brass pipes of various sizes and over a very wide range of velocities with air, water, and viscous oil. They showed that if the function ($R/\rho v^2$), which is equivalent to the usual friction factor (see later), is plotted against the Reynolds number, a single curve is obtained under all conditions.

In other words, for any particular value of Reynolds number, whether the fluid was air, water, or oil, the pipe large or small, only one value of the friction factor ($R/\rho v^2$) was obtained. This type of curve is known as a Stanton Curve, and is illustrated on Fig. 1.

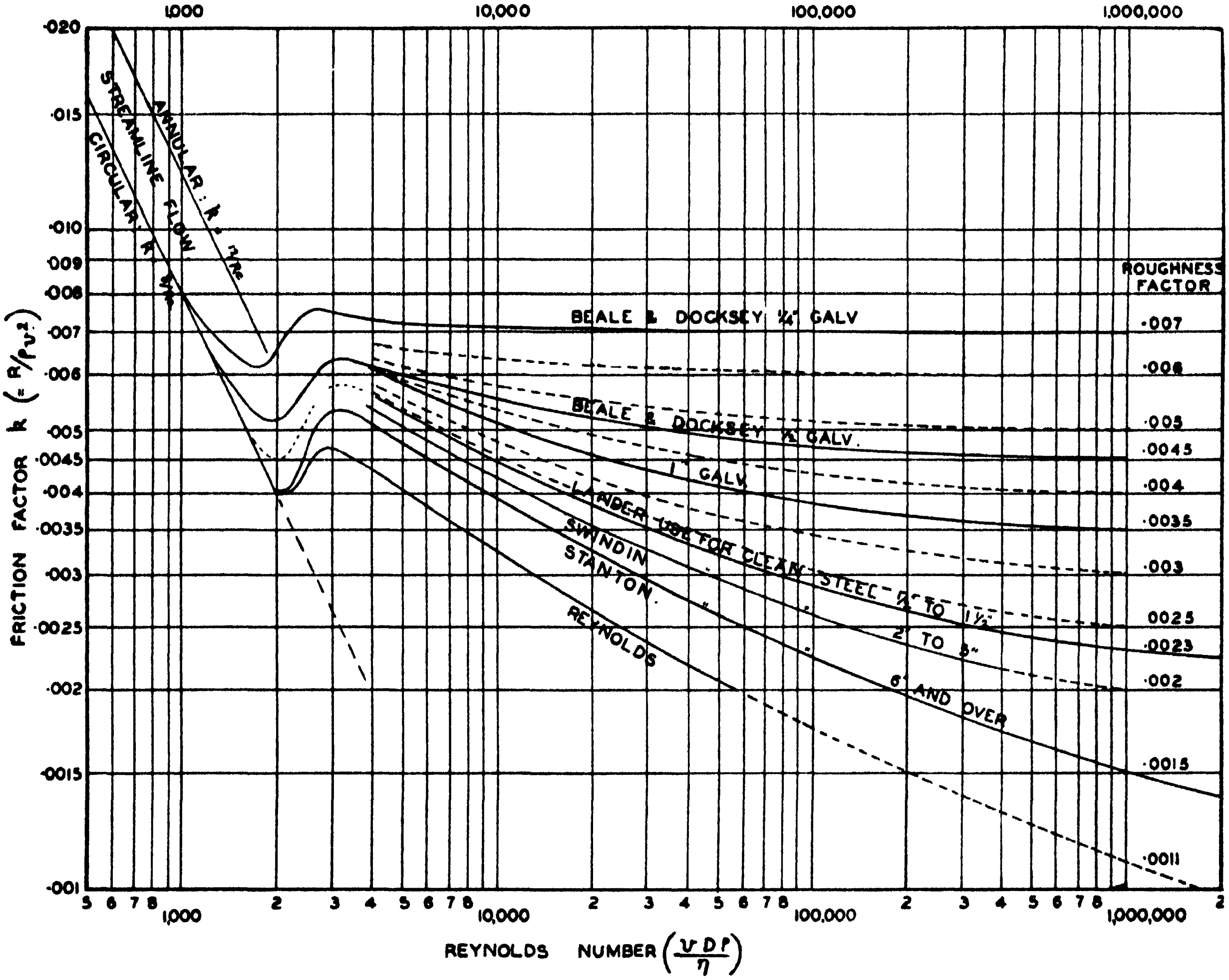


FIG. 1.

This result is of the utmost importance and is an illustration of the Principle of Dynamic Similarity which has been the subject of many investigations in connexion with aerodynamics and, notably by Stanton and Pannell, as applied to flow in pipes.

In this application the principle may briefly be stated as follows: In two geometrically similar pipe systems, when the Reynolds number is the same in both, the motion will be exactly similar in all respects.

The requirement of geometrical similarity in this case means that the shape of the surface irregularities must be the same in both cases and their linear dimensions must in each case be in proportion to the pipe diameter. This was verified experimentally by Stanton [32, 1911] by means of two brass pipes of diameter 7·35 cm. and 5·08 cm., each of which was cut with exactly similar right- and left-hand threads internally, the pitch of the threads being in proportion to the diameter of the pipes.

These surfaces were chosen to represent a 'perfectly rough' pipe, and the pressure drop was found to be almost exactly proportional to the square of the velocity, or in other words, the friction factor was found to have a constant value independent of the velocity, and the value was exactly the

same for both pipes. The velocity distribution across the cross-section was also the same in both, thereby demonstrating the principle of dynamic similarity.

This has a most important bearing on the influence of surface roughness on the friction factor in commercial pipes. This subject is treated in detail later, but it may be here pointed out that according to the above principle the surface irregularities in a large pipe, say, 12 in. in diameter, should be 12 times the size of those in a 1-in. pipe for the two to be similar.

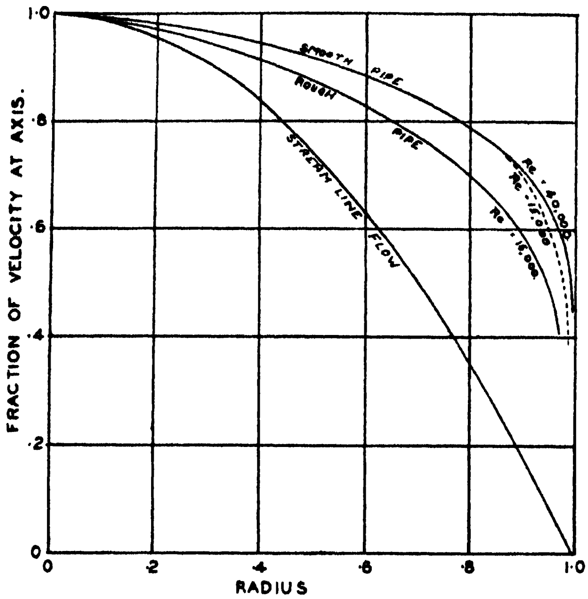


FIG. 2.

The velocity distribution over the cross-section for Stanton's rough pipes is shown in Fig. 2. That for smooth pipes at the same value of R_e is shown for comparison

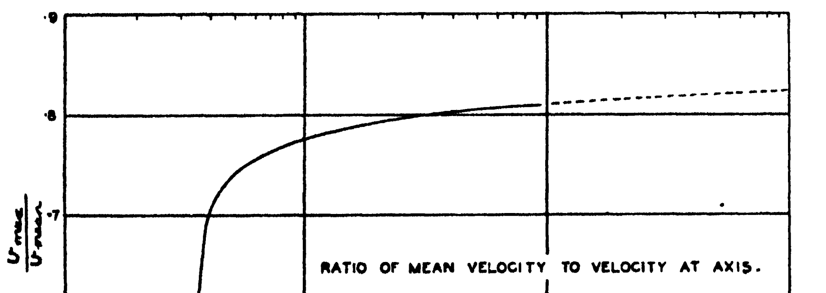


FIG. 3.

together with the parabolic curve representing stream-line flow.

On Fig. 3 is plotted the ratio mean velocity/maximum velocity for smooth pipes against R_e. This ratio for stream-line flow is 0·5, but when turbulence occurs the ratio rises rapidly to 0·7, and as R_e becomes very large the ratio reaches a limiting value of about 0·82. The curve up to $R_e = 100{,}000$ is that given by Stanton and Pannell, and the extrapolated part is in fair agreement with the results of other workers. The fact that all results for air and water in smooth brass pipes from 0·7125 to 5·08 cm. in diameter fell closely on one curve is further evidence of the similarity of motion, and is useful when a Pitot Tube is used for the measurement of flow in a pipe.

Stream-line Flow

As mentioned above, in stream-line or viscous flow the pressure drop due to friction in a pipe is proportional to the velocity and to the viscosity of the fluid. The equation for this case may be written in the following equivalent forms for self-consistent units:

$$p = \frac{128\eta L q_m}{\pi D^4 g} = \frac{32\eta L v}{D^2 g} = \frac{8\eta L v}{r^2 g} \tag{1}$$

$$q_m = \frac{\pi}{128}\,\frac{D^4 p g}{\eta L} = \frac{\pi r^4 p g}{8\eta L}, \tag{2}$$

where p = pressure drop, gravitational units, e.g. *grams* per sq. cm.
q_m = rate of volume flow,
v = mean linear velocity,
D, r = diameter and radius of the pipe,
η = absolute viscosity,
L = length of pipe,
g = acceleration due to gravity.

This equation was originally established experimentally by Poiseuille [24, 1842] in an extremely thorough investigation, using water and alcohol flowing in capillary tubes, and the equation goes by his name. It was derived theoretically soon afterwards by Neumann and by Hagenbach in 1860. The kinetic energy correction was worked out rigorously by Boussinesq [4, 1891], and a correction for the viscous friction associated with the ends of the tube was given by Couette [6, 1890].

The Kinetic Energy Correction is of general application to all types of flow and is dealt with later under Entrance and Exit Losses, but the second correction to Poiseuille's equation, known as the Couette Correction, applies only to stream-line flow, and it is seldom of importance in pipe flow, since it is only appreciable when the length of the pipe is very short as in the case of jets of commercial viscometers.

With stream-line flow in a circular pipe, to which Poiseuille's equation applies, the distribution of velocity across the cross-section is parabolic, with the maximum velocity at the centre and zero velocity at the walls. The velocity of all particles is parallel to the axis, and there are no accelerations at any point. When these conditions do not apply, as, for instance, near the entrance to a pipe or when the cross-section of the channel varies, due, for instance, to large surface irregularities, Poiseuille's equation is not applicable except as an approximation. However, it has been shown by Wilson, McAdams, and Seltzer [38, 1922] that in the case of reasonably large pipes of normal commercial quality Poiseuille's equation applies within the limits of experimental error regardless of the type of surface, so that it appears that the surface irregularities are not great enough to affect the flow.

Viscous Flow between Concentric Pipes

The equation for flow between concentric cylinders has been given by Lamb [18, 1916] as follows:

$$v = \frac{p}{32\eta L}\left[D^2+d^2-\frac{D^2-d^2}{\log_e D/d}\right] \tag{3}$$

where D = diameter of the outer cylinder,
and d = diameter of the inner cylinder.

When $(D-d)$ is very small this reduces to the case of flow between two parallel planes, and writing $\frac{1}{2}(D-d) = x$,

$$v = \frac{px^2}{12\eta L}. \tag{4}$$

Where d is zero, the equation, of course, reduces to that for a plain circular pipe, but, as pointed out by Kemler [15, 1933], it cannot be assumed that when d is small its effect is negligible. For instance, when $d = D/10$ the inner cylinder only occupies 1% of the cross-section, but according to the formula the flow will be reduced to 57% by its presence in the pipe.

Turbulent Flow

The fundamental equation expressing the pressure drop along a pipe in which fluid is flowing may be written thus:

$$p = 8\left(\frac{R}{\rho v^2}\right).\frac{L}{D}.\frac{\rho v^2}{2}, \tag{5}$$

where p = pressure drop,
R = frictional force per unit area of wetted pipe surface,
ρ = density of fluid,
v = mean linear velocity of fluid,
L = length of pipe,
D = diameter of pipe.

This equation holds as it stands for any set of self-consistent units, when p is a force divided by an area (i.e. poundals per sq. ft., or dynes per sq. cm). If p is measured in gravitational units (i.e. lb. per sq. ft., or g. per sq. cm.) and for the sake of brevity we write for the friction factor $k = (R/\rho v^2)$, the equation becomes

$$p = 8k.\frac{L}{D}.\frac{\rho v^2}{2g}. \tag{6}$$

All flow equations, both for gases and liquids, are based on this equation, which is substantially the same as the D'Arcy or Fanning equation except that it is written so as to keep intact the term $\rho v^2/2g$, which is known as the 'velocity head'. This arrangement is adopted because, as will be seen later, allowances for bends, elbows, &c., are best made in terms of velocity head.

This equation may be written in an equivalent form for use with the volume rate of flow, q_m, in place of the mean velocity, namely:

$$p = 8k.\frac{L}{D}.\frac{8\rho q_m^2}{\pi^2 g D^4}, \tag{7}$$

the last term in this equation is also the 'velocity head'.

Before these equations can be used in practice it is necessary to do three things:

(1) Determine the value of k.
(2) Arrange the equation for use with suitable units, and in a convenient form.
(3) Determine the allowance to be made for incidental pipeline losses, pipe fittings, bends, &c.

The three subjects will be dealt with in this order.

The Friction Factor k.

The friction factor as ordinarily used in pipe flow refers to the constant in the equation for hydraulic flow of the type given above. As, however, there are several variations of this equation in current use in which the friction factor (usually denoted by the letter f) has a numerical value 2, 4, or 8 times that of the constant in equations (5), (6), and (7), to avoid ambiguity the dimensionless group $(R/\rho v^2)$ will be used for the friction factor in this article and will be denoted by k. R in this group is simply the frictional force per unit area of the pipe wall.

It has already been explained that the friction factor depends essentially on the Reynolds number, and therefore the relation between these two functions is best shown on a graph such as Fig. 1, on which k is plotted against R_e. The friction factor, as might be expected, also depends on the roughness of the pipe surface when the flow is turbulent, and it will be seen that there are several curves drawn on this figure, each of which shows the relation between k and R_e for a particular type of pipe.

Each of these curves simply represents the results of practical experiments, and their shapes have no theoretical basis with the exception of the straight lines representing stream-line flow on the left of the figure. The lower straight line applies to circular pipes, and its equation is $k = 8/R_e$. This may easily be derived by comparing equation (1) with equation (6), when it will be seen that if $8\eta/vD\rho$ is substituted for k in equation (6), the two equations become identical.

The most important theoretical feature of this method of plotting is based on the principle of dynamic similarity and has been very thoroughly proved by experiment, and it is this: At any given Reynolds number the friction factor taken from a curve representing one particular pipe will be exactly the same whatever fluid is flowing through the pipe, provided, of course, the fluid does not alter the condition of the pipe surface. This statement is necessarily confined to true Newtonian fluids and cannot be applied to non-Newtonian liquids and plastics without reservations. For instance, the line marked 'STANTON' shows the results of Stanton and Pannell's experiments on the flow of air, water, and oil in smooth brass pipes 0·361–12·61 cm. in diameter [33, 1914].

Relative Roughness.

Another general feature of great practical importance based on the same theoretical principle concerns the choice of curve to represent any particular pipe by the use of the idea of 'relative roughness'. As has been explained above, if the size and spacing of the asperities on the surface of two pipes of different diameters are in exact proportion to the diameters, then k will be the same for both at the same R_e, and therefore the same curve will accurately represent both pipes and the two pipes may be said to have the same relative roughness. In just the same way, if two pipes of different diameters have surface irregularities of the same size, the larger pipe will be relatively smoother and have the lower friction factor.

In practice, of course, the asperities on different sized pipes can never be strictly similar geometrically, nor will the shape and size of the irregularities be quite identical in different pipes made of the same material and by the same process. Nevertheless, experience shows that these principles can be applied very satisfactorily in practice to pipes of commercial quality. For instance, Stanton and Pannell's curve representing smooth brass pipes of small diameter

also represents very closely clean steel pipes of commerical quality of considerably larger diameter (10 to 15 in.). These large steel pipes are considerably less relatively rough than small steel pipes of the same type of surface as represented by the curve marked 'LANDER'. This curve in turn may be used to represent pipes of larger diameter with larger and more numerous surface irregularities such as cast-iron or galvanized pipes.

The only kind of pipe which should not be subject to this 'scale effect' is a perfectly smooth pipe with a highly polished surface. Reynolds's curve for 'drawn lead pipe' approaches this condition and may be taken to represent the lower limit of smoothness, but here again this curve may be taken to represent smooth bitumen-coated pipes several feet in diameter.

A family of curves of increasing relative roughness can thus be drawn as in Fig. 1, and the appropriate curve selected for use in any particular case from recommendations based on practical experience.

A very comprehensive set of curves have been drawn up by Piggott [23, 1933] based on the work of Kemler [15, 1933] who correlated practically all the experimental data on pipe flow in the turbulent region up to 1932. He gives a set of evenly spaced lines covering the area between the curve for very smooth pipes and a horizontal line for $k = 0{\cdot}00675$ which he gives as the upper limit of surface roughness, excluding cases where there may be additional losses due to changes of cross-section. It will be noted that this is also the value found by Stanton for internally screwed pipes. An extensive table of recommendations for the use of this chart for the various types of commercial pipe is also given by this author.

Shape of Curves.

In all carefully conducted experiments on commercial pipes covering a wide range of Reynolds number such as those of Stanton and Pannell [33, 1914], and Lander [19, 1916], it has been found that, when log k is plotted against log R_e, as in Fig. 1, the lines are continuously curved throughout their length in the turbulent region (k decreasing as R_e increases), but with a tendency to become horizontal as R_e becomes large. The value of R_e at which k becomes sensibly constant is lower with the rougher than with the smoother pipes. These two features are to be seen in Fig. 1 and also from the empirical formulae which have been evolved to represent two of the most reliable curves, namely,

$$\text{STANTON } k = 0{\cdot}0765 R_e^{-0{\cdot}35} + 0{\cdot}0009$$
$$\text{LANDER } k = 0{\cdot}141 R_e^{-0{\cdot}44} + 0{\cdot}002.$$

The first equation was given by Lees [20, 1914] and represents the results obtained by Stanton and Pannell [33, 1914]. It also represents very closely indeed the extensive experiments of Saph and Schoeder [28, 1903] (quoted by Stanton [32*a*]) on similar drawn brass pipes. The second equation is of the same form and represents Lander's experiments [19, 1916] on steel pipes.

From this it follows, as has been pointed out by Swindin [34, 1924], that flow formulae of the 'logarithmic' type, i.e. $p \propto v^n$, are unsound for general application since n changes continuously with R_e, although, as explained below, this type of formula is very useful and accurate over a limited range of R_e. For these reasons a family of curves of the type given in Fig. 1 based on actual experimental determinations is to be preferred to the more arbitrary straight lines with sudden changes of direction given by Kemler and Piggott (and others). This family has been based on the six experimental lines shown. The two lines for rough pipes by the authors were chosen because they covered a wide range of Reynolds number. The intermediate lines of the family shown dotted were drawn in by cross-plotting; while lines of greater roughness can be drawn with a constant value of k without serious error.

Scale of Roughness

It is of considerable value to have some simple scale of relative roughness by which commercial pipes, both new and old, can be classified.

Piggott's chart provides such a scale, but the authors do not consider this to be entirely satisfactory, for two reasons. Firstly, the lines representing the smoother pipes are definitely not the best representation of the well-substantiated experiments by many workers, and secondly, the spacing and numbering of these lines, which together form the scale of roughness, are quite arbitrarily chosen.

It is therefore suggested that a better scheme is to draw a self-consistent family of curves such as that in Fig. 1, in the best possible agreement with the well-authenticated results for smooth pipes, and to use as a scale of roughness the value of the friction factor at some convenient value of R_e, such as one million. On this basis the curve of Reynolds would be 0·001, Stanton 0·0015, Swindin 0·002, Lander 0·0023, and the curves interpolated between the experimental lines on Fig. 1 have been chosen to have round numbers on this scale of relative roughness. Other values can, of course, be easily interpolated by eye.

Although it is found that practical measurements on pipelines, whether of new or corroded pipe, usually fit in reasonably well with a family of curves of this type, it must be realized that this is not the only possible shape of curve for rough pipes. The composite graphs given by Kemler show lines crossing at various angles not all of which will probably be due to experimental error. In the case of very rough pipes, and in particular when this is due to corrosion, an actual reduction in mean diameter cannot be ignored in practice. This at once introduces the probability of some departure from the family of curves. If as a result of corrosion the diameter of a pipe were reduced by, say, 10% without an increase in surface roughness, the friction factor (calculated on the original diameter) would be increased by 60% at all values of R_e; whereas the family shows a greater proportional increase in k at high values of R_e than at low. The experiments of Nikauradse [22, 1931], Fromm [10, 1923], Fritsch [9, 1928], and Schiller [29, 1923], &c., on artificially roughened pipes show that k may fall with increasing R_e at first, and then start rising; becoming constant above a certain value of R_e. Alternatively k may rise in a series of steps as R_e increases. Stanton also noticed a tendency for k to rise with increasing R_e in his experiments on internally screwed pipes.

Nikauradse's experiments on pipes internally coated with sand of various grades show curves of the former type, which form a well-defined family arranged in order of increasing roughness defined by the ratio

$$\frac{\text{mean height of surface irregularity}}{\text{diameter of pipe}}$$

and they have been analysed theoretically by Prandtl [25, 1933] on this basis. Curves of this type, however, are seldom met with in practice, so that this method of analysis is primarily of theoretical interest. Piggott claims that the above ratio may be used for estimating the roughness in

commercial pipes by treating the projections simply as causing a reduction of effective diameter. This can, however, hardly be a true picture, as it would give a different type of curve for rough pipes to that observed.

It is probably necessary to consider at least two types of surface friction, one due to tangential force on the pipe wall in the direction of flow, and the other due to forces normal to the surfaces of the asperities. The latter has been examined by Fage [8, 1933]. The critical velocity for the flow round the individual asperities no doubt controls the Reynolds number at which k becomes constant, and the size and number of them controls the actual value of k. In practice the size, shape, and distribution of the asperities are so varied that the overall result is the sum of a large number of separate effects, resulting in a gradual flattening of the curve.

The practical conclusion on the question of choosing the curve appropriate to any particular flow problem is that in the absence of specific data the general recommendations in the table should be followed in the case of new pipes. The allowance to be made for increase of roughness with time due to corrosion, incrustation, solid deposits, &c., can only be settled from experience with the particular fluids in question, since it is well known that some unrefined products in a refinery cause rapid deposits and a rapid rise in friction, while others containing much free H_2S, as, for instance, some crude oils, show no signs of increased friction whatever after many years.

A discussion on the conditions which lead to internal corrosion of pipelines is perhaps out of place in the present article, but it may be mentioned that the simultaneous presence of H_2S moisture, and oxygen (usually in the form of dissolved air which has been picked up due to exposure in storage tanks), is usually the cause of severe roughening of the surface of mild steel pipes and a rapid rise in roughness from the 'clean' value.

It is noticeable that distillates from highly sulphurous crudes which have not been exposed to air at any time are seldom corrosive, and pipelines carrying them remain 'clean' for many years. Partly refined oils, however, which have been in intimate contact with aqueous solutions, and which may also have dissolved some air, are often found to be severely corrosive unless they have been very thoroughly settled.

It is very desirable in practice to calculate k and R_e for any pipeline when circumstances permit a satisfactory measurement to be made. By putting the point so obtained on a chart of the type of Fig. 1 experience can be gained as to the appropriate curve for any particular duty.

Friction Factor for Non-circular Sections

The flow in channels of non-circular cross-section has not been investigated in such detail as that in circular pipes, but some method of dealing with such cases is needed on exactly the same lines as for pipes. The Reynolds number can be evaluated without ambiguity by using the Hydraulic Mean Depth as the characteristic linear dimension of the channel in place of the diameter of the circular pipe. The hydraulic mean depth m is defined as the ratio of

$$\frac{\text{cross-sectional area}}{\text{wetted perimeter}},$$

and for a circular pipe, $D = 4m$; therefore for a channel of any cross-section

$$R_e = \frac{4vm\rho}{\eta}.$$

A corresponding substitution is necessary in the appropriate equation of flow, and equation (6) becomes

$$p = 2k.\frac{L}{m}.\frac{\rho v^2}{2g}, \tag{6a}$$

but it will be realized that equations involving q, such as equation (7), cannot be used in this way, but must first be converted to the corresponding equation in terms of v.

It has been found [16] that to a reasonable degree of approximation the same friction factor k may be used for non-circular channels in equation (6) as for circular pipes of the same surface roughness at the same Reynolds number, and changes in the relative roughness of the surface may be expected to have just the same effect on the friction factor. For instance, Atherton [1, 1926] found that the friction factor for the annular space between pipes was about 25% greater than for the circular pipes forming it.

The critical velocity for the flow between concentric cylinders has been investigated by Lonsdale [21, 1923], who found that it was determined by the relation

$$\frac{v_c(D^2-d^2)}{\nu D} = 4{,}000.$$

The hydraulic mean depth is $m = (D-d)/4$, and when $(D-d)$ is made very small this reduces to the case of flow between parallel planes (equivalent to a very narrow closed rectangular channel), and the formula for the critical velocity becomes

$$\frac{4v_c m}{\nu} = 2{,}000.$$

Jeffrey [14, 1925] has investigated the corresponding case of an open rectangular trough and finds that $4v_c m/\nu$ is about 1,250.

Here again the critical velocity for a channel, which departs very greatly from the circular shape, corresponds with that for a circular pipe, but in the region of stream-line flow there is a difference. It has been pointed out above that for a circular pipe the friction factor in stream-line flow is given by $k = 8/R_e$, whereas if equation (4) is compared with equation (2) it will be seen that for flow between parallel planes $k = 12/R_e$. This line is shown on Fig. 1, and it will be seen that for smooth channels of this section there is little or no room for S bends in the critical region, and therefore the transition from stream-line to turbulent flow may be expected to take place more gradually than in a circular pipe.

The flow between parallel planes represents the extreme departure from the circular section, and therefore other sections met with in practice will behave intermediately.

The calculation of flow in passages of constantly varying cross-section such as in the shell of heat exchangers where the flow usually takes place across the tubes can only be treated in a much more empirical manner and is outside the scope of this article. It may be said, however, that the application of the general principles given here is undoubtedly the best way of treating this problem also [30, 1934], but it should be borne in mind that turbulent flow occurs at much lower values of R_e in divergent channels and much higher values in convergent channels as demonstrated by Gibson [11, 1909].

Critical Region

The flow characteristics in the region of transition between stream-line and turbulent flow are less stable than in the other two regions. This is not surprising, since it can easily be seen that in this region the onset of turbulence

may be retarded by keeping the pipe free from bends, constrictions, or surface irregularities; or accelerated by such disturbing agents. This region, which may extend from $R_e = 1{,}000$ to 3,000, is called the critical region, because for any pipe the critical velocity, i.e. that at which stream-line flow changes to turbulent flow, lies within this range of R_e.

The value of k in the critical region must be obtained from the Stanton curves (Fig. 1), and all the remarks which have been already made on the subject of pipe roughness and the procedure for estimating k apply equally to this region also. It is necessary, however, to consider briefly the characteristics of the curves in this region.

If, for instance, Stanton and Pannell's experimental results are examined, it will be seen that while the S-shaped curve shown on Fig. 1 represents the results, the deviation of individual results from this mean line is far greater in this region than when the flow is fully turbulent.

The reason for this is the general instability of the character of flow in this region. On account of this some authorities recommend extrapolating the smooth curve which gives the value of k in the tubulent region, through the critical region to meet the line for stream-line flow. The S bend is thus disregarded, and the values of k taken from the extrapolated portion of the curve are regarded as representing the upper limit of the scattered experimental values which are obtained in this region. It has been shown, however, by Beale and Docksey [3, 1932] that if values of k are determined in the critical region by experiments in which the pressure drop is kept constant, the results obtained are consistent and are represented by the S bend. These experiments give the *mean* value of k, determined for the period during which the volume of fluid flowing through the pipe is measured, and since this closely represents the practical case, it is recommended that in the critical region the value of k should be taken from the S-shaped curves.

The significance of this characteristic shape of the curves in this region is that the friction factor increases rapidly with the Reynolds number and may be nearly proportional to it over the middle range. This means that the pressure drop is proportional to the cube of the rate of flow over this range, and therefore an unusually large increased pressure is necessary to increase the rate of flow, by a given percentage, and also the effect of viscosity changes are as important as in stream-line flow, but in the opposite direction, an increased viscosity causing an increased rate of flow for a given pressure drop.

Evaluation of the Reynolds Number

The Reynolds number is essentially a pure number having no dimensions, and the only satisfactory procedure is to express it in some set of self-consistent units, and if this is done the Reynolds number has the same numerical value whatever system is chosen. It should be noted that some European writers use the radius of the pipe in place of the diameter, thus obtaining a value for the Reynolds number which is half that obtained if it is calculated from the expression given here.

The most convenient set of self-consistent units for this purpose is probably the c.g.s., since viscosities are usually given in poises and kinematic viscosities in stokes.

When the quantities are given in other units they may each be converted to the c.g.s. or some other self-consistent units by means of the usual conversion factors. The nomogram Fig. 4 may also be found convenient. Alternatively the Reynolds number can be calculated, using a mixed set of units and the result multiplied by the appropriate conversion factor. For instance, a set of units often used in America gives the function usually written DUS/Z, where D is in inches, U in ft. per sec., S the specific gravity relative to water, and Z in centipoises. In this case the result must be multiplied by 7,740 to give the Reynolds number.

Similarly, if it is found more convenient to use, instead of v the mean linear velocity, either q_m the rate of volume flow or w the rate of mass flow, the Reynolds number becomes (all in self-consistent units):

$$R_e = \frac{vD}{\nu} = \frac{4}{\pi} \times \frac{q_m}{D\nu} = \frac{4}{\pi} \times \frac{w}{D\eta}$$

If other units are used, an appropriate factor must be used in place of $4/\pi$. A selection of the factors more commonly required are given in the table below.

TABLE I

Factors for calculating R_e

(η in centipoises, ν in centistokes)

v	q	w	D	R_e
ft. per sec.	..	..	in.	7,742 $\times (vD/\nu)$
m. per hr.	..	..	m.	277·8 $\times (vD/\nu)$
.	cu. ft. per hr.	..	in.	394·3 $\times (q/D\nu)$
.	imp. gal. per hr.	..	in.	63·30 $\times (q/D\nu)$
.	bbl. per hr.	..	in.	2,214 $\times (q/D\nu)$
.	m.^{3} per hr.	..	m.	353·7 $\times (q/D\nu)$
..	..	lb. per hr.	in.	6·344 $\times (w/D\eta)$
	..	kg. per hr.	m.	1,273 $\times (w/D\eta)$

Note. Poises $\times$ 0·0672 = f.p.s. units
Stokes $\times$ 0·001076 = f.p.s. units.

In the above expressions the values for v, q_m, η, and ν must be those at the conditions of flow. If the temperature varies slightly the mean temperature should be used, but if the temperature variation is large and an accurate result is wanted, the pipe should be treated in sections, over each of which the temperature range is comparatively small.

In the case of a gas the four quantities just mentioned are affected not only by temperature but also by pressure. However, η does not vary much with pressure, and the product $v\rho$ or $q_m\rho$ is independent of pressure, hence the Reynolds number will not vary from one end of the pipe to the other, due to the change of pressure. Furthermore, the value of R_e will be correctly calculated if the gas is assumed to be at any convenient pressure, and this is usually taken to be 1 atmosphere. In this case v must be the velocity and q_m the volume per unit time calculated for a pipe of diameter D at *1 atmosphere pressure* and at the mean temperature of flow, and ν is the kinematic viscosity also at 1 atmosphere and the mean temperature of flow.

In the case of the weight formula the only quantity affected by pressure is η, and as has been said the effect of pressure is small and therefore its effect may be ignored.

Calculating R_e for a gas by inserting values for 1 atmosphere in the expressions given above is greatly facilitated if a graph giving kinematic viscosities of gases at 1 atmosphere is available [40].

This method of determining R_e in the case of gas flow is very quick and convenient, but it must be remembered that it suffers from the inaccuracy due to failure to allow for deviation from the gas laws. When R_e is high, as it usually is in the case of gas flow, its value is not required with great accuracy, and hence the deviation from the gas laws may be omitted when calculating it without introducing serious error. When, however, the flow is near the critical region R_e must be known more accurately, and it is best in these

cases to work out R_e at the mean pressure in the pipe, and correcting v, q_m, ρ, and η for the effect of pressure.

Nomogram for the Evaluation of Reynolds Number.

The nomogram given on Fig. 4 gives a convenient method of estimating R_e when the quantities are in British or c.g.s. units.

Evaluation of k

When R_e has been evaluated, the value of the friction factor k may be obtained from Fig. 1. The curves plotted on Fig. 1 have been taken from the following sources:

TABLE II

Authority	*Type of surface*	*Pipe diameter in.*
Reynolds [27] . .	drawn lead	$\frac{1}{4}$–$\frac{1}{2}$
Stanton [33] . .	drawn brass	$\frac{1}{7}$–5
Swindin [34] . .	rubber hose	1
Lander [19] . .	drawn steel	$\frac{1}{2}$–$1\frac{1}{4}$
Beale and Docksey [3] .	galvanized iron	$\frac{1}{2}$
Beale and Docksey [3] .	galvanized iron	$\frac{1}{4}$

There is an additional line for galvanized iron pipe which is founded on Gibson's results [12, 1925], but with the shape of the line slightly modified to fit the family of curves.

The recommendations for applying the curves to steel and galvanized pipe are given on the graph. The meagre results on clean cast-iron pipe in the literature indicate that it is of the same relative roughness as galvanized pipe. The increase in roughness due to fouling can only be arrived at as the result of experience. The article by Kemler [15, 1933] in which all the available published results on clean and dirty pipe have been correlated is extremely useful in this connexion.

Incidental Pipeline Losses

There are two accepted methods for allowing for the effect of joints, fittings, and incidental losses generally in a pipeline, namely, either to add a certain number of diameters for each fitting to the length of the line, or to increase the pressure drop by a certain number of velocity heads. It can easily be shown that if one of these methods is fundamentally sound the other is not. The 'velocity head method' is undoubtedly sound in the case of changes of section, entrance, and exit, and experiments show that it is preferable for fittings as well [3, 1932]. The 'additional length method', on the other hand, is much easier to apply to the flow equations given below. That being the case, the course is adopted here of giving the allowance to be made for fittings in terms of *velocity heads*, and giving a rule by which the velocity heads may be converted to additional length.

If C is the number of velocity heads lost due to one or more pipe fittings and N is the corresponding number of pipe diameters which should be added to the actual length of the pipe, then, when the friction factor k is known for the particular pipe and rate of flow, the two can be interconverted by the following equation:

$$N = \frac{C}{8k}.$$

It should be noted that the length of the pipe to which the additional length should be added is the length of the pipe along the centre line with the fittings in position, and caution is needed when L and D are in different units.

The allowance to be made for fittings depends on whether the flow is stream-line or turbulent. There have not been many determinations over a large range of R_e, but the graphs in Figs. 5 and 6 show the effect in the case of loss due to elbows and to enlargement and contraction, and it is suggested that the allowances for other fittings should be modified in the light of the curves shown on these graphs when it is desired to know the allowance for a fitting in or near the critical region.

Elbows. Variation with R_e.

Fig. 5 shows the loss due to one elbow in a straight pipe plotted against the Reynolds number. This graph is founded on the experimental results of Beale and Docksey [3, 1932] obtained on relatively smooth and very rough pipes.

It is shown in the paper referred to that the loss due to one elbow can be expressed as a single curve applicable to smooth and rough pipes if the loss is expressed in velocity heads. If, on the other hand, the loss is expressed in added length, the curves for rough and smooth pipes diverge. Wilson, McAdams, and Seltzer [38, 1922] have carried out a large number of experiments on elbows, and compared them with those of other workers. They express the loss in terms of additional length. The values they arrive at are in good agreement with Fig. 5.

It will be seen that the loss tends to reach a steady value at high values of R_e in the turbulent region, and this enables approximate numerical values to be given for various kinds of fittings which are applicable to thoroughly turbulent flow.

Fittings, Bends, and Elbows (Turbulent Flow).

In Table III is given a range of values for the loss in velocity heads for some usual pipe fittings indicating the effective limits found with good and bad fittings of commercial quality. It is recommended that the lower figure should be used if the fitting is clean, smooth, and of good form, and any burr removed from the joint, while the upper limit should be taken for rough and badly jointed fittings.

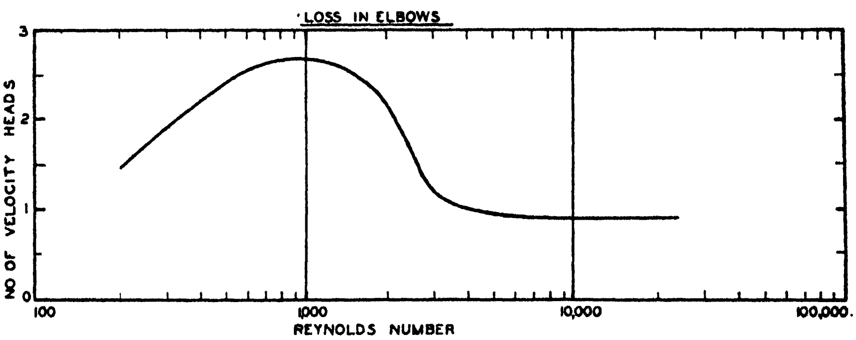


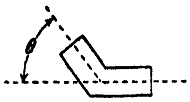
FIG. 5.

TABLE III

Type of fitting	*C = no. of velocity heads*
Normal 90° bend .	0·25–0·5
90° elbow . .	0·8–1·2
Tee . . .	1·0–1·8
Globe valve . .	1·0–1·6

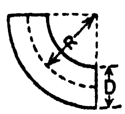
The losses due to elbows and 90° bends of different shapes may be taken as follows:

Elbows of Various Angles



θ	C
90°	1·0
60°	0·36
45°	0·18
30°	0·07
15°	0·02

90° Bends of Various Curvatures



R/D	C
0·5	1·0
0·75	0·75
1·0	0·60
1·5	0·47
2·0	0·40
4–10	0·30

The losses due to a pipe fitting occur partly in the fitting itself, but to a considerable extent also in the pipe immediately following it. For this reason the losses due to two or more fittings close together are less than those due to the same fittings well spaced. As an example of this it should be mentioned that the pressure drop in a continuous coil cannot be obtained from the results from 90° bends given above. Spiers [31, 1932] states that the pressure drop in continuous coils in turbulent flow may be calculated by multiplying the pressure drop for a straight pipe at the same Reynolds number by the factor $e^{\pi D/R}$, where the pipe diameter D and the radius of the coil R are in the same units.

The pressure drop in coils for stream-line flow and the critical velocity has been investigated by White [37, 1929] and Taylor [35, 1929], and a useful summary of their work is given by Spiers.

Entrance and Exit Loss (Variation with R_e).

The allowances to be made for a square-edged entrance and exit from a large tank are given in Fig. 6, which shows the variation of these losses with Reynolds number [3, 1932] expressed in terms of velocity head.

At high values of R_e the loss tends towards a constant value. The values given below for various changes of section in a pipe all refer to such high values of R_e in the turbulent region. When the flow is stream-line the entrance and exit loss is usually negligible in all except very short pipes. The losses under these conditions were originally investigated by Boussinesq and Couette and are dealt with in text-books on viscometry [2, 1931].

Enlargement and Contraction Losses (Turbulent Flow).

The number of velocity heads to be allowed for enlargement and contraction in the cross-section, such that

$$b = \frac{\text{area of small section}}{\text{area of large section}}$$

are:

Sudden enlargement $C = (1-b)^2$
Sudden contraction* $C = 0{\cdot}5(1-b)$
Sharp-edged orifice† $C = \left(\frac{1}{C_c} - b\right)^2$

where‡ $C_c = (0{\cdot}61 + 0{\cdot}39b^3)$.

* The factor $(1-b)$ is a simple approximation which is well within the limits of agreement of the various experimental results [11, 1925; 36, 1927].

† This gives the permanent loss of pressure due to the orifice regarded as an obstruction to flow, and not the pressure difference when the orifice is used as a meter.

‡ The expression for C_c is an approximation obtained from a consideration of the results of Davis and Jordan quoted by Gibson [11, 1925].

The graph in Fig. 6*a* shows the relationship between C and b for the various cases.

It is suggested that the results for the sharp-edged orifice could be used as an approximation to the effect of any more or less sharp-edged obstruction such as a partly closed gate-valve.

Bell-mouthed entrance or gradual contraction of angle less than 30°	$C = 0{\cdot}05$ (usually negligible)
Re-entrant mouthpiece . . .	$C = 1{\cdot}0$
Square entrance from a large tank (This is obtained by putting $b = 0$ in the equation above for sudden contraction.)	$C = 0{\cdot}5$

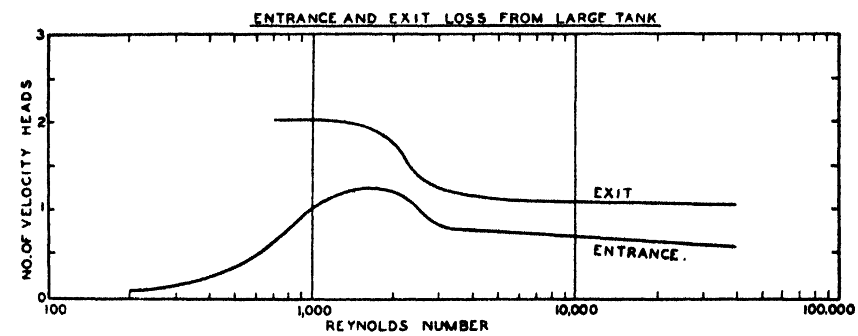
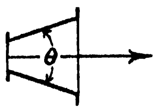


FIG. 6.

The value for the exit loss has been calculated from a knowledge of the distribution of the velocity over the cross-section, and the entrance loss obtained by experiment. As would be expected, the disturbance of flow due to the entrance has the effect of increasing the loss in the critical region.

Exit into a large tank . . . (This is obtained by putting $b = 0$ in the equation above for sudden enlargement.)	$C = 1{\cdot}0$
For a gradual enlargement of total angle θ	$C = f(1-b)^2$

The values for f, for various values of θ, are given in the following table.



θ	f
8°	0·15
14°	0·25
20°	0·45
30°	0·70
45°	0·95
60°	1·1
90–180°	1·0

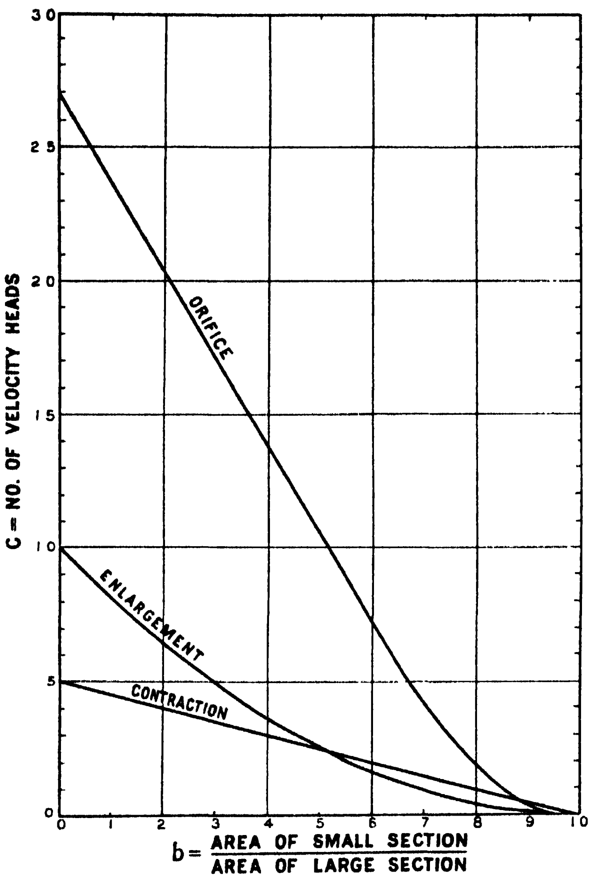


FIG. 6a.

Effect of Joints.

Joints in a pipeline increase the frictional losses, and this may be treated as an increase in the value of k. This subject has been investigated by Kite and Kennedy [17, 1922] and by Beale and Docksey [3, 1932]. The recommendations on Fig. 1 for using the curves for steel pipes apply for unjointed or very smoothly jointed lines. The results of Kite and Kennedy indicate that for normal screwed lines the value of k should be increased in accordance with the second column in Table IV.

TABLE IV

Effect of Joints in Turbulent Flow

Values of R_e	Increase in k: Rough joints	Increase in k: Smooth joints
Up to 5,000 . .	15%	5%
5,000 to 20,000 .	10%	3%
Above 20,000 .	5%	2%

On the other hand, Beale and Docksey found by the simple process of cutting a pipe and joining it up again that the effect due to screwed joints was not greater than 5% except in the critical region, where it might be as much as 12% and depended considerably on the form of the joint. Their recommendations for screwed joints were as given in the last column. These two columns may then be taken to represent the upper and lower limits for normal types of screwed joints depending on whether they are rough or smooth inside.

In the case of welded joints which have been carefully made without the formation of internal icicles, as, for instance, the double-bell type with internal sleeve, no allowance need be made for the joints. Where, however, the internal condition is not so certain as with a butt joint, it may be advisable to make a small allowance such as that in the last column of Table IV.

Flow Equations

The rate of flow of a fluid may be expressed in terms of the volume flowing in unit time, or of the mean linear velocity in the pipe. The former of these is by far the most generally useful.

There are many flow formulae used in practice, their forms being dictated by the units used for the various quantities and by various simplifications which can be introduced if the equation is intended to apply only to a limited range of conditions. The following equations are all based on the fundamental flow equations, the derivation of which will be found in the standard books on hydraulics. These equations are usually derived for self-consistent units, and a list of them follows. The simple equations for stream-line flow and for the flow of liquids in the turbulent region need no comment or explanation; the flow equations for a gas are somewhat more complicated, and it is necessary to realize the limitations from which they may suffer. This point is briefly referred to below.

In all these equations the effective length of the pipe, L', is used, i.e. the actual length plus any additional length due to fittings, &c., as a reminder that some allowance for incidental losses may have to be made.

Static Head.

It should be understood that all the equations below deal only with the pressure drop due to friction and do not include any static pressure differences between the two gauge points. In order to get the total pressure difference this static pressure difference must clearly be added to or subtracted from the frictional pressure drop according as the static pressure at the inlet end is less than or greater than that at the exit end.

If, as is usual, gauge pressures and not absolute pressures are measured, the mean density of the outside air between the two points should be subtracted from the density of the fluid inside the pipe in calculating the static pressure difference. This may be of importance in the case of low-pressure gas flow where, of course, the static gauge pressure may be greatest at the point of greatest elevation.

Stream-line Flow.

Liquids, and gases with low pressure drop.

$$p = \frac{32\eta L'v}{D^2g} = \frac{128}{\pi}\frac{\eta L'q_m}{D^4g} \tag{1}$$

$$q_m = \frac{\pi}{128}\frac{D^4gp}{\eta L'}. \tag{2}$$

It is important to remember that, in this equation, and in the equation for liquids in turbulent flow, q_m is the volume flowing at the temperature (and pressure) of flow, and has not been reduced to standard conditions.

Turbulent Flow.

Liquids and gases with low pressure drop.

$$p = 8k \cdot \frac{L'}{D} \cdot \frac{\rho v^2}{2g} \tag{6}$$

$$= 8k \cdot \frac{L'}{D} \cdot \frac{8\rho q_m^2}{\pi^2 g D^4} = \frac{64kL'\rho q_m^2}{\pi^2 g D^5} \tag{7}$$

$$q_m = \frac{\pi}{8}\sqrt{g}\sqrt{\left(\frac{D^5 p}{k\rho L'}\right)}. \tag{8}$$

Turbulent Flow: Gases.

The flow equation for gases can be derived from first principles from the equation of energy. In deriving it, the assumption is usually made that the gas obeys Boyle's law, or at any rate that $P_1 V_1 = P_2 V_2$, where P_1, V_1 are pressure and specific volume at entrance and P_2, V_2 at exit from the pipe. Unless this assumption is made a very complicated equation results. The assumption does not introduce a serious error in most cases.

A more serious error may be introduced if it is assumed that the volume flowing can be reduced to standard conditions using the gas laws. As will be seen later, this assumption can be discarded without making the equations more complicated.

In its complete form the flow equation for a gas is

$$\frac{P_1^2 - P_2^2}{2P_1} = 2\left(4k\frac{L'}{D} + \log_e\frac{P_1}{P_2}\right)\frac{\rho_1 v_1^2}{2g}. \tag{9}$$

The expression $(P_1^2 - P_2^2)$, which occurs in the above and in the equations which follow, can also be written $2P_m p$, where P_m is the mean pressure $(P_1+P_2)/2$, and p is the pressure drop. The substitution has not been made in the equations given here, but it is convenient to bear the alternative form in mind.

As L' is increased, $4kL'/D$ becomes large compared with $\log_e(P_1/P_2)$ and the equation can be simplified to

$$\frac{P_1^2 - P_2^2}{2P_1} = 8k \cdot \frac{L'}{D} \cdot \frac{\rho_1 v_1^2}{2g}. \tag{10}$$

In practice it is usually considered safe to use this simpler form when $L/D > 200$.

If the pressure drop is low, i.e. 5% of the mean pressure, then P_m may be put equal to P_1 without serious error, and the equation then becomes the same as equation (6).

We can substitute for ρ_1 and v_1 in equation (9) in terms of ρ_s, the density of the gas at standard temperature and pressure T_s, P_s, and q_s the volume flowing reduced to S.T.P. If μ is the deviation from the gas laws [5, 1931] defined by $PV/RT = \mu$, then

$$\frac{P_1}{RT\rho_1} = \mu_1 \quad \text{and} \quad \frac{P_s}{RT_s\rho_s} = \mu_s.$$

Therefore $$\rho_1 = \rho_s \times \frac{T_s P_1}{TP_s} \times \frac{\mu_s}{\mu_1}.$$

Similarly, $$q_1 = q_s \times \frac{P_s T}{P_1 T_s} \times \frac{\mu_1}{\mu_s}$$

$$v_1 = q_1 \div \frac{\pi D^2}{4}$$

If these substitutions are made in equation (9), and the equation simplified, we obtain

$$q_s = \frac{\pi}{8}\sqrt{g}\sqrt{\frac{T_s}{P_s}}\sqrt{\left\{\frac{4D^4(P_1^2-P_2^2)}{2\left(4k\frac{L'}{D}+\log_e\frac{P_1}{P_2}\right)T\rho_s}\cdot\frac{\mu_1}{\mu_s}\right\}}. \tag{11}$$

The equation corresponding to equation (10), when $L/D > 200$ is

$$q_s = \frac{\pi}{8}\sqrt{g}\sqrt{\frac{T_s}{P_s}}\sqrt{\left\{\frac{D^5(P_1^2-P_2^2)}{2kL'\rho_s T}\cdot\frac{\mu_1}{\mu_s}\right\}}. \tag{12}$$

When the pressure drop is low, the equation may be further simplified to

$$q_s = \frac{\pi}{8}\sqrt{g}\sqrt{\left(\frac{T_s P_m}{P_s T}\right)}\sqrt{\left(\frac{D^5 p}{kL'\rho_s}\cdot\frac{\mu_1}{\mu_s}\right)}. \tag{13}$$

If we express the density of the gas in terms of G, the specific gravity relative to air, and if we simplify the equations by taking the term $P_s/T_s\rho_{sA}$ into the constant, we obtain the following equations from (11) and (12).

$$q_s = K\frac{T_s}{P_s}\sqrt{\left\{\frac{4D^4(P_1^2-P_2^2)}{\left(4k\frac{L'}{D}+\log_e\frac{P_1}{P_2}\right)GT}\cdot\frac{\mu_1}{\mu_s}\right\}} \tag{14}$$

$$q_s = K\frac{T_s}{P_s}\sqrt{\left\{\frac{D^5(P_1^2-P_2^2)}{kL'GT}\cdot\frac{\mu_1}{\mu_s}\right\}}. \tag{15}$$

Weymouth's well-known formula is equivalent to equation (15), but it assumes that k is a function of the diameter only given by $k = 0{\cdot}004/D^{\frac{1}{3}}$.

Owing to the inclusion of the term $P_s/T_s\rho_{sA}$ in the constant, the latter is no longer dimensionless, and its value is not the same in all systems of self-consistent units. The values of K for the (c.g.s. ° C.) system and (f.p.s. ° F.) system are

$K = 470{\cdot}4$ for c.g.s. ° C. system
$K = 11{\cdot}5$ for f.p.s. ° F. system.

Equations in Practical Units. As already explained, there are so many forms of flow equation in use that it would be impossible in this article to give a representative list. All flow equations whose use can be recommended are founded on the equations just given. A few of the many practical formulae are given below. They have been chosen so that workers in British, American, and metric units will be provided with an equation suitable for units with which they are familiar.

When the calculation is being made to obtain the value of the pressure drop, q_m and D being known, the value of R_e can be obtained directly. When, however, the object of the calculation is to obtain q_m or D it is first necessary to assume a value for k, work out q_m or D, and then check the value of k by obtaining R_e and referring to the graph. A more nearly correct value of k is then chosen and the calculation remade. There is no way of avoiding this method of approximation except by the use of the complete equations for the flow, which are discussed later. These equations are, however, only applicable over a restricted range and are not intended for general calculations.

The use of a nomogram makes this process of successive approximation very quick, and for very accurate work when the nomogram is not exact enough the final calculation can be made, using in the equation the value of k found by the use of the nomogram.

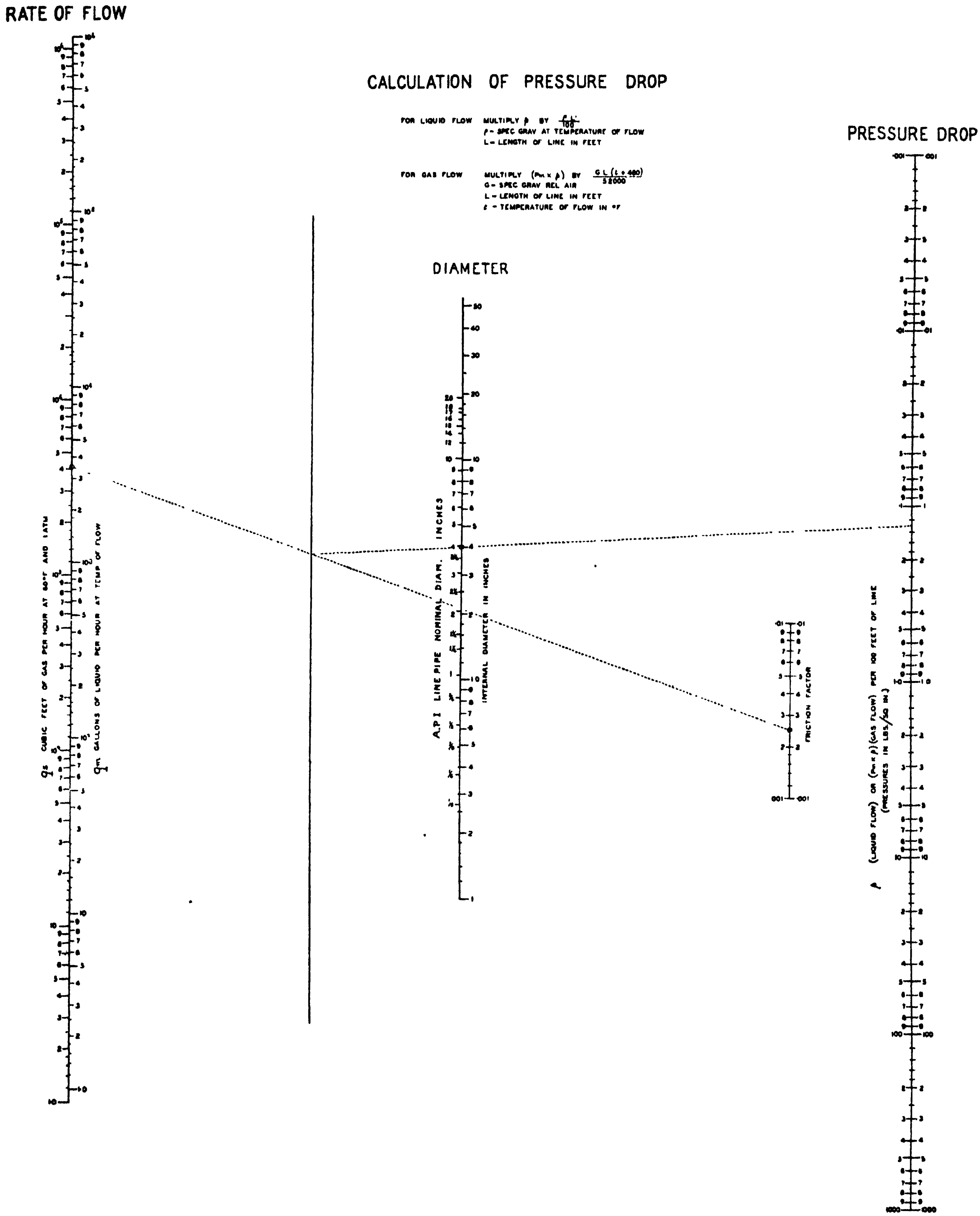

RATE OF FLOW
CALCULATION OF PRESSURE DROP
FOR LIQUID FLOW MULTIPLY p BY ρL/100
ρ - SPEC GRAV AT TEMPERATURE OF FLOW
L - LENGTH OF LINE IN FEET
FOR GAS FLOW MULTIPLY (Pm x p) BY GL(t + 460)/52000
G - SPEC GRAV REL AIR
L - LENGTH OF LINE IN FEET
t - TEMPERATURE OF FLOW IN °F
PRESSURE DROP
DIAMETER
qs CUBIC FEET OF GAS PER HOUR AT 60°F AND 1ATM
qm GALLONS OF LIQUID PER HOUR AT TEMP OF FLOW
A.P.I LINE PIPE NOMINAL DIAM. INCHES
INTERNAL DIAMETER IN INCHES
FRICTION FACTOR
p (LIQUID FLOW) OR (Pm x p)(GAS FLOW) PER 100 FEET OF LINE
(PRESSURES IN LBS/SQ IN)

Fig. 7.

Stream-line Flow : Liquids.

$$q_m = K\frac{D^4gp}{\eta L'}$$

For self-consistent units $K = \pi/128$

Throughput q_m	Length L'	Diam. D	Pressure drop P	Viscosity η	g	K
imp. gal. per hr.	ft.	in.	lb. per sq. in.	centipoises	32·2	5,700
bbl. per hr.	ft.	in.	lb. per sq. in.	centipoises	32·2	163

Turbulent Flow: Liquids.

$$q_m = K\sqrt{\left(\frac{D^5p}{k\rho L'}\right)} \qquad p = \frac{1}{K^2}\cdot\frac{q_m^2 k\rho L'}{D^5}$$

For self-consistent units $K = (\pi/8)\sqrt{g}$

Throughput q_m	Length L'	Diam. D	Pressure drop p	Density ρ	K	$\frac{1}{K^2}$
gal. per hr.	ft.	in.	lb. per sq. in.	sp. gr. rel. water	152	$4\cdot33\times10^{-5}$
bbl. per hr.	ft.	in.	lb. per sq. in.	sp. gr. rel. water	4·35	0·0528
cu. m. per hr.	m.	m.	kg. per sq. m.	kg. per cu. m.	$4\cdot43\times10^{3}$	$5\cdot10\times10^{-8}$

Turbulent Flow : Gases.

$$q_s = K\sqrt{\left\{\frac{4D^4P_mp}{\left(4k\frac{L'}{D}+\log_e\frac{P_1}{P_2}\right)GT}\cdot\frac{\mu_1}{\mu_s}\right\}} \quad \text{when } \frac{L}{D} < 200$$

$$q_s = K\sqrt{\left(\frac{D^5P_mp}{kL'GT}\cdot\frac{\mu_1}{\mu_s}\right)} \quad \text{when } \frac{L}{D} > 200$$

Throughput q_s	Standard temp.	Standard press.	Length L'	Diam. D	Press. P_m and p	Sp. gr. G	Flowing temp. T	K
cu. ft. per hr.	60° F.	14·7 lb. sq. in.	ft.	in.	lb. per sq. in.	rel. air	° F. Abs.	4,154
cu. m. per hr.	0° C.	760 mm. Hg	m.	m.	kg. per sq. m.	rel. air	° C. Abs.	676·0

The factor μ_1/μ_s is usually assumed to be equal to 1·0, and should be given this value except in cases where P_m is high and great accuracy is required.

Nomogram for Solution of Flow Equations (Fig. 7).

The nomogram in Fig. 7 has been drawn to solve the equations

$$q_m = K\sqrt{\left(\frac{D^5p}{k\rho L'}\right)}$$

and $$q_s = K\sqrt{\left(\frac{D^5P_mp}{kL'GT}\right)}.$$

The nomogram has been drawn assuming L' to be 100 ft., ρ and G both to be equal to 1·0, and T equal to 520° F. Abs.

Hence to use the nomogram for a liquid of density ρ flowing in a pipe L' ft. long, the pressure drop, as read from the nomogram, must be multiplied by $\rho L'/100$.

To use the nomogram for a gas of sp. gr. (relative to air) $= G$, flowing in a pipe L' ft. long at T ° F. Abs., $P_m \times p$ as read from the graph must be multiplied by $GL'T/52{,}000$.

Complete Equations for Limited Range

It is sometimes desirable to use an equation which can be solved without reference to a chart in order to determine the value of k. Such complete equations could be constructed by writing k in terms of $vD\rho/\eta$ in any of the above equations by means of the empirical expressions for the appropriate Stanton curve such as those given by Lees and Lander. This leads, however, to very cumbersome expressions, and for simplicity in calculation a slightly different method should be used.

Owing to the fact that the slope of the lines on Fig. 1 changes continuously with the Reynolds number, as has been pointed out above, it is not strictly correct to write $k = aR_e^{-n}$, but owing to the fact that all the curvatures on Fig. 1 are small an expression of this type is remarkably accurate over a restricted range of R_e if the values of a and n are chosen correctly. In a great many applications of the flow formulae the actual range of R_e covered in any particular problem is reasonably small. It is seldom, for instance, greater than 4 to 1, and in such cases the error due to the use of this simple relation between k and R_e is less than $\pm 2\frac{1}{2}\%$ if the values used correspond to the middle of the range of R_e.

The use of this simple relation leads to very simple formulae particularly adapted to logarithmic calculation, for instance, equations (6) and (7) become

$$p = \frac{4a}{g} \times \frac{L\eta^n\rho^{1-n}v^{2-n}}{D^{1+n}} \tag{16}$$

$$p = \frac{64a}{4^n\pi^{2-n}g} \times \frac{L\eta^n\rho^{1-n}q^{2-n}}{D^{5-n}}. \tag{17}$$

The values of a and n for the curves given in Fig. 1 are shown in Figs. 8 and 9.

It may here be mentioned that the effect of joints is not included in any of these curves, but is simply to be added to the value of a in the form of a percentage as indicated above, the value of n being unaffected.

As a typical example the pressure drop in the 8 to 12-in. pipes composing the Anglo-Iranian Oil Company's main crude-oil pipeline from the oilfields to the refinery at

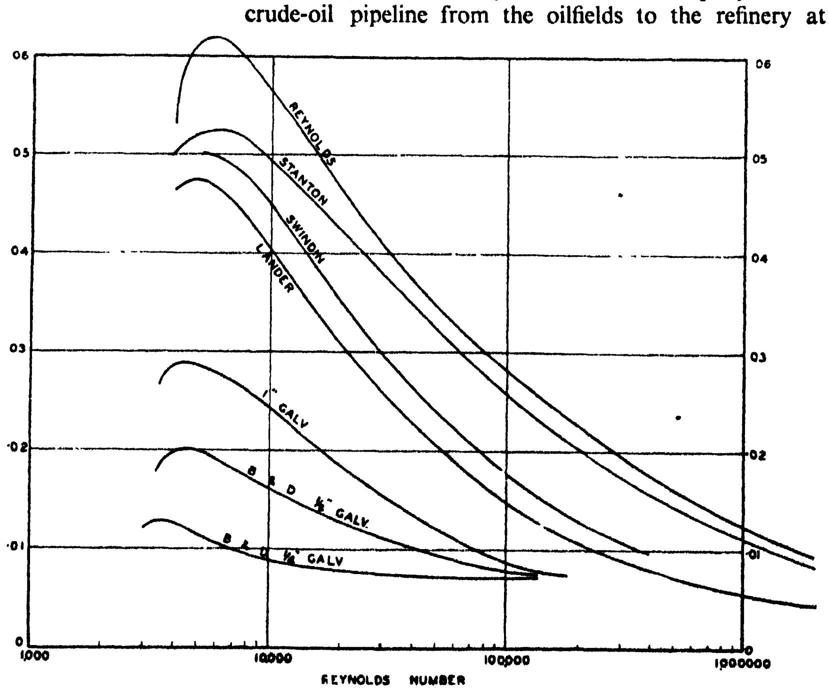


FIG. 8.

Abadan has been found to be accurately represented by the line marked STANTON on Fig. 1 with an increase of 4% for the screwed joints, and a value of n equal to 0·23 in the above equations has been used for many years over the normal range of R_e averaging about 50,000.

Equations (16) and (17) become for this case

$$p = \frac{0{\cdot}135}{g} \times \frac{L\eta^{0\cdot23}\rho^{0\cdot77}v^{1\cdot77}}{D^{1\cdot23}}$$

$$p = \frac{0{\cdot}207}{g} \times \frac{L\eta^{0\cdot23}\rho^{0\cdot77}q^{1\cdot77}}{D^{4\cdot77}}.$$

This type of equation is particularly adapted to the calculation of the effect of small changes in any of the factors which influence the flow in pipelines such as in calculating the increase in pressure at a pumping station required to increase the throughput by a given percentage or to overcome the effect of a change in viscosity of the oil.

Parallel Pipelines

A development of this type of equation is particularly adapted to the calculation of problems involving pipes connected in parallel with the help of the idea of an 'equivalent line' of a standard diameter having the same total throughput at the same pressure drop; a method proposed by Heltzel [13, 1934].

By substituting

$$k = \frac{a}{(vD\rho/\eta)^n}$$

in equation (17) and rearranging we get an equation of the form

$$q = B\left[\frac{D^{5-n}}{L}\right]^{\frac{1}{2-n}} \tag{18}$$

in which the constant B contains the pressure and temperature terms and the relevant properties of the fluid. If it is assumed that the inlet and outlet pressures as well as all the properties of the fluid remain the same after paralleling, the value of B remains unaltered in the case of both liquids and gases.

Consider a system of parallel lines all having the same length L_1 and the same operating conditions. Let d_1, d_2, d_3, &c., represent diameters, and Q_1, Q_2, Q_3, &c., the quantities flowing through each line respectively; we therefore have

$$\left.\begin{aligned} Q_1 &\propto \left(\frac{d_1^{5-n}}{L_1}\right)^{\frac{1}{2-n}} \\ Q_2 &\propto \left(\frac{d_2^{5-n}}{L_1}\right)^{\frac{1}{2-n}}, \text{ \&c.} \end{aligned}\right\}. \tag{19}$$

Let L represent the length of an equivalent line of a standard diameter D which will give the same total throughput, hence

$$Q \propto \left(\frac{D^{5-n}}{L}\right)^{\frac{1}{2-n}}, \tag{20}$$

where $$Q = Q_1+Q_2+Q_3+\ldots. \tag{21}$$

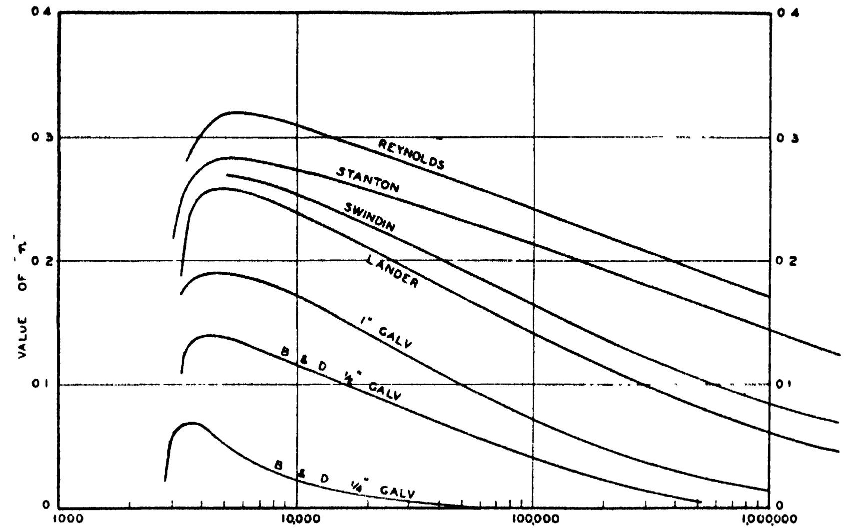


FIG. 9.

From (19), (20), and (21) we get

$$\left(\frac{D^{5-n}}{L}\right)^{\frac{1}{2-n}} = \left(\frac{1}{L_1}\right)^{\frac{1}{2-n}}\left(d_1^{\frac{5-n}{2-n}}+d_2^{\frac{5-n}{2-n}}+d_3^{\frac{5-n}{2-n}}+\ldots\right) \tag{22}$$

or $$\frac{L}{L_1} = \frac{D^{5-n}}{\left(d_1^{\frac{5-n}{2-n}}+d_2^{\frac{5-n}{2-n}}+d_3^{\frac{5-n}{2-n}}+\ldots\right)^{2-n}} = \alpha, \text{ say,} \tag{23}$$

where α = ratio of the length of the equivalent line to the length of the parallel system and may be referred to as the *Length Ratio*.

To simplify calculations in designing parallel pipeline systems, equation (23) can be rewritten as follows:

$$\left(\frac{1}{\alpha}\right)^{\frac{1}{2-n}} = \left(\frac{d_1}{D}\right)^{\frac{5-n}{2-n}}+\left(\frac{d_2}{D}\right)^{\frac{5-n}{2-n}}+\left(\frac{d_3}{D}\right)^{\frac{5-n}{2-n}}+\ldots$$

$$= M_1+M_2+M_3\ldots = \sum M, \tag{24}$$

where $$M_1 = \left(\frac{d_1}{D}\right)^{\frac{5-n}{2-n}},$$

$$M_2 = \left(\frac{d_2}{D}\right)^{\frac{5-n}{2-n}}, \text{ \&c.}$$

$\sum M$ can be regarded as the number of standard diameter pipes in parallel of the same length as the actual system which would give the same throughput with the same operating pressures.

$\sum M$ and M_1, M_2, &c., may be referred to as the *Equivalent Number*.

Values of M can be tabulated for the various standard

pipe diameters and for various values of n all compared with some standard diameter D which may, for instance, be 12 in., since the actual internal diameter of an A.P.I. 12-in. pipe is exactly 12·00. This has been done in Table V below.

To reduce a system of parallel lines of length L_1 to a corresponding length of an equivalent line of the standard diameter, the values of M can be read from the table for the nearest value of n as predicted from Fig. 9.

Having calculated $\sum M$ from the values of M, the *Length Ratio*, α, can then be obtained from equation (24) which can be rewritten in the form

$$\alpha = \frac{1}{(\sum M)^{\frac{1}{2-n}}}. \qquad (25)$$

In this way any system of parallel lines connected together at each end can be reduced to an equivalent line of a standard diameter. By this means problems can be greatly simplified, such as: To calculate the effect on the throughput under the same operating conditions of adding a line in parallel with an existing line or set of parallel lines, or To calculate the necessary diameter of a new line to be put in parallel with a given system to give a certain increase in throughput under the same operating conditions. The actual value chosen for the standard diameter is of no consequence as long as the value of n taken from Fig. 9 and used in the calculation refers to the actual pipes and not to the standard diameter.

TABLE V

n	0	0·05	0·1	0·15	0·2	0·25	0·3	0·35
d (in.)	Equivalent number M.							
3 (3·068)	0·03306	0·03122	0·02966	0·02803	0·02638	0·02466	0·02302	0·02142
4 (4·026)	0·06515	0·06246	0·05975	0·05710	0·05434	0·05151	0·04874	0·04602
5 (5·047)	0·1147	0·1109	0·1071	0·1032	0·09924	0·09517	0·09111	0·08710
6 (6·065)	0·1817	0·1769	0·1721	0·1674	0·1621	0·1569	0·1516	0·1462
7 (7·065)	0·2659	0·2605	0·2549	0·2493	0·2434	0·2372	0·2310	0·2247
8 (7·981)	0·3608	0·3551	0·3492	0·3434	0·3370	0·3305	0·3237	0·3169
9 (8·941)	0·4787	0·4735	0·4679	0·4620	0·4560	0·4493	0·4427	0·4360
10 (10·136)	0·6558	0·6510	0·6465	0·6416	0·6371	0·6317	0·6263	0·6212
12 (12·00)	1·0000	1·0000	1·0000	1·0000	1·0000	1·0000	1·0000	1·0000
14 (13·25)	1·280	1·286	1·290	1·296	1·302	1·308	1·317	1·322
15 (14·25)	1·536	1·546	1·557	1·569	1·581	1·593	1·607	1·624
16 (15·25)	1·820	1·837	1·854	1·874	1·893	1·915	1·938	1·964
17 (16·214)	2·120	2·145	2·172	2·200	2·230	2·262	2·296	2·335
18 (17·182)	2·451	2·485	2·521	2·620	2·602	2·646	2·695	2·749
20 (19·182)	3·225	3·286	3·347	3·415	3·488	3·566	3·648	3·749

List of Symbols

- R_e Reynolds number $= vD\rho/\eta$.
- k Friction factor $= R/\rho v^2$.
- R Frictional force per unit area of pipe wall.
- D, d Diameter of pipe.
- r Radius of pipe.
- L Length of pipe.
- L' Effective length of pipe, i.e. actual length $L+$ additional length, for fittings, &c.
- v Mean linear velocity of fluid in pipe.
- v_1 Mean linear velocity of gas upstream conditions.
- q Volume flowing in unit time.
- q_m Volume flowing in unit time under mean flowing conditions.
- q_1 Volume flowing in unit time under upstream conditions.
- q_s Volume flowing in unit time reduced to P_s and T_s.
- w Mass flowing in unit time.
- p Pressure drop, gravitational units, e.g. grams/sq. cm.
- P_1, P_2 Upstream and downstream pressures (absolute).
- P_m Mean pressure (absolute) $= (P_1+P_2)/2$.
- P_s Standard pressure (1 atm. = 760 mm. Hg = 14·7 lb. per sq. in.).
- ρ Density of fluid under mean flow conditions.
- ρ_1 Density of fluid under upstream conditions.
- ρ_s Density of fluid at P_s and T_s.
- ρ_{sA} Density of air at P_s and T_s.
- G Specific gravity of gas relative to air (at P_s, T_s).
- η Absolute viscosity of fluid.
- ν Kinematic viscosity of fluid $= \eta/\rho$.
- μ Deviation from gas laws.
- μ_1 Deviation from gas laws at upstream conditions.
- μ_s Deviation from gas laws at P_s and T_s.
- V_1, V_2 Specific volume at upstream and downstream conditions.
- T Temperature of flow (Absolute).
- T_s Standard temperature (520° F. Abs. or 273° C. Abs.).
- C Number of velocity heads to be added (allowance for fittings).
- N Number of pipe diameters to be added (allowance for fittings).
- b Ratio of area of small section to area of large section.
- g Acceleration due to gravity.
- a Constant in flow equation for limited range.
- n Index in flow equation for limited range.
- α Length ratio (parallel lines).
- M Equivalent number (parallel lines).

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ARTICLES

39. BEALE, E. S. L. Flow of Waxy Oils and other Non-Newtonian Liquids.
40. —— Viscosity of Gases and Vapours.
41. LAWRENCE. Anomalous Viscosity.
42. DE WAELE. Measurement of Plasticity.

THE FLOW OF WAXY OILS AND OTHER NON-NEWTONIAN LIQUIDS

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Introduction

THE laws governing the flow of true liquids and gases in pipes are well established under all conditions of flow, but, as is well known, waxy oils and other fluids containing solid matter in suspension behave differently, particularly at low rates of flow, and their behaviour in any given circumstances is very much more difficult to predict. This is due to several factors. One outstanding reason is that such a fluid often shows quite a different consistency depending on the previous thermal and mechanical treatment. An instance of the former is the gelling property of waxy fuel oils and of the latter the thixotropy shown by certain drilling muds. It should be clearly understood that in this article the behaviour of liquids with a definite consistency, which can be determined in a suitable form of viscometer or plastometer, only is considered, and not the change of this consistency under different conditions; nor is the possible deposition of solid matter on the walls of the pipe taken into account.

Apart from the changeable character of some fluids the subject is made much more difficult owing to the fact that, whereas there is only one set of laws governing the behaviour of true or 'Newtonian' liquids, a separate set of equations must be applied to each distinct type of 'non-Newtonian' liquid of which there are several recognizable classes.

In this article an attempt is made to give the basic principles underlying the behaviour of non-Newtonian liquids in the simplest terms, since, unless these are very clearly understood, confusion of thought may obscure the more complex results observed with such liquids.

The treatment of the subject presumes that the behaviour of true or Newtonian liquids in pipes is well understood, for which reference should be made to another article [17].

A true liquid, or 'Newtonian' liquid, is one in which the rate of shear is proportional to the shearing stress, and therefore, at any given temperature and pressure, there is one unique value for the viscosity under whatever conditions of shearing stress it is determined (provided, of course, that the flow remains laminar and kinetic energy effects are absent). It also follows that some flow will take place however small the applied pressure.

A non-Newtonian liquid is one in which the rate of shear is not proportional to the shear stress, or in other words, it does not possess a definite viscosity at any one temperature and pressure like a true liquid, but the apparent viscosity, or its reciprocal the apparent fluidity, changes as the rate of shear or the shear stress changes. Such liquids very often also show a certain shear strength which enables them to resist deformation by an applied pressure up to a certain value without any appreciable flow taking place.

The simplest example of this is known as a 'Bingham Body', whose characteristics are described below. A body of this type should really be classed as a soft solid or a plastic, since the existence of a limiting shear strength is the essential feature of this class of material. Strictly speaking, a non-Newtonian liquid is one which does not show this shear strength, but as the two classes tend to merge into each other due to seepage and to slippage at the walls, for the purposes of the present article both types will be referred to as non-Newtonian liquids.

Typical instances of such liquids which are met with in petroleum technology are:

1. Waxy oils near their setting-point.
2. Drilling mud and cement slurry.
3. Foams of gas in oil, and oil in water emulsions.

These fall into various classes according to their behaviour under stress, and the distinction between the main classes are best illustrated by means of a diagram, Fig. 1, which is based on one given by Merkel [13, 1934]. The diagram shows the rate of shear, or velocity gradient, plotted against the shear stress causing it, and below are illustrations of the velocity distribution across the cross-section when the flow takes place in a circular pipe.

Before considering the various characteristic curves in Fig. 1 it should be clearly understood that each of these curves describes the internal frictional properties of the liquid itself, as far as possible independent of the design of the particular apparatus used in the determination of them, in the same way that the viscosity of a true liquid is a sufficient description of its internal frictional properties and can be given without reference to the dimensions of the viscometer used.

For example, it is the first essential that the flow during the determination shall be laminar, since turbulence would vitiate the results completely. It may here be pointed out that although the laws governing the change from laminar to turbulent flow are not well defined in the case of non-Newtonian liquids, yet there is no doubt that above a certain critical velocity turbulent flow does occur, and where this type of flow has been thoroughly established the distinction between Newtonian and non-Newtonian liquids becomes small and, as in the case of Newtonian liquids, the density becomes the chief property of the liquid controlling the flow, whereas the viscosity becomes of secondary importance only.

A further requirement in any satisfactory viscometer is that kinetic energy effects should be small enough to be neglected or should be allowed for. Unfortunately, as has been pointed out by Scott Blair [6, 1930], this is frequently not the case, and the result is that such data is of little use for purposes of calculation, although it may be quite adequate for the routine control, for instance, of the consistency of a series of drilling muds or cement slurries of the same type [16, 1935]. It has been maintained by Wo. Ostwald that turbulence in such materials is a necessity in order to maintain the properties of the liquid in a state representative of that existing in practice [2, 1936]. However, to obtain values useful for calculation efflux type viscometers must be very carefully designed in order to avoid kinetic energy effects and turbulence in the jet, particularly when dealing with thin drilling muds. Rotary

viscometers such as the concentric cylinder type, or the Störmer, designed with a view to maintaining a uniform mixture and adequate mechanical working of the liquid, must be run at a speed low enough to suit the liquid under observation [1, 1931; 11, 1934].

An obvious difficulty in testing any viscometers for these effects is that, whereas in the case of a Newtonian liquid it is a simple matter to verify whether such disturbing effects are present by observing whether the flow is proportional to the stress, this method cannot be applied to a liquid for which this law does not hold. It is therefore necessary to depend on calculation of these effects or experiment using the nearest equivalent Newtonian liquid.

In the present article attention is chiefly directed to the use of the efflux type of viscometer, as in this case the relationship between observed flow and pressure can usually be simply calculated from the dimensions and the properties of the liquid, and a simple relation exists between laminar flow in the jet of the viscometer and in a large pipe. With rotary viscometers the calculations are usually more complex, and in some types empirical relationships only are possible.

An important exception to this generalization is the concentric cylinder rotary viscometer in which the ratio of the radii of the inner and outer cylinders is very nearly unity. This apparatus, particularly in those designs in which the end effects are eliminated [12, 1932] or are made to conform with the conditions in the cylindrical part [14, 1934], gives a direct measure of the characteristic curves as illustrated in Fig. 1, since the shear stress and the rate of shear is substantially uniform throughout the liquid under test.

The practical use of viscometers is outside the scope of the present article, but it may be here pointed out that, with liquids whose properties may depend on so many factors, it is usually essential to make the condition of the liquid while being tested as nearly as possible identical with those under which the liquid will be used in practice.

Some liquids are found to have different structures and properties when tested in concentric cylinder and efflux viscometers, so that the greatest circumspection is necessary in applying laboratory results to the large scale.

Stress/Shear Curves

In Fig. 1 to the left of the point D are plotted curves which represent the fundamental properties of typical liquids from which their behaviour in any particular circumstances can be calculated. A curve of this type may be called the *Stress/Shear* curve of the liquid to distinguish it from the *Consistency* curve which shows the behaviour of the liquid in a practical viscometer. The consistency curve is discussed later and may or may not be the same shape as the stress/shear curve.

In the present article the properties of the liquid are referred to in terms of viscosity rather than of fluidity or mobility in order to bring out the relationship to the flow of Newtonian liquids more clearly.

It is necessary for the terms used to be very clearly defined.

In general, viscosity is a shear stress divided by a rate of shear, the rate of shear being the velocity gradient measured in a direction at right angles to the motion, and fluidity is the reciprocal of the viscosity. A line of a given slope on Fig. 1 therefore represents a given viscosity. In the case of Newtonian liquids no further qualification is needed because all lines representing them are straight and pass through the origin; but when, as shown in Fig. 1, the lines have varying slopes and do not necessarily pass through the origin we must distinguish between two types of viscosity, and this is best done by reference to a specific example.

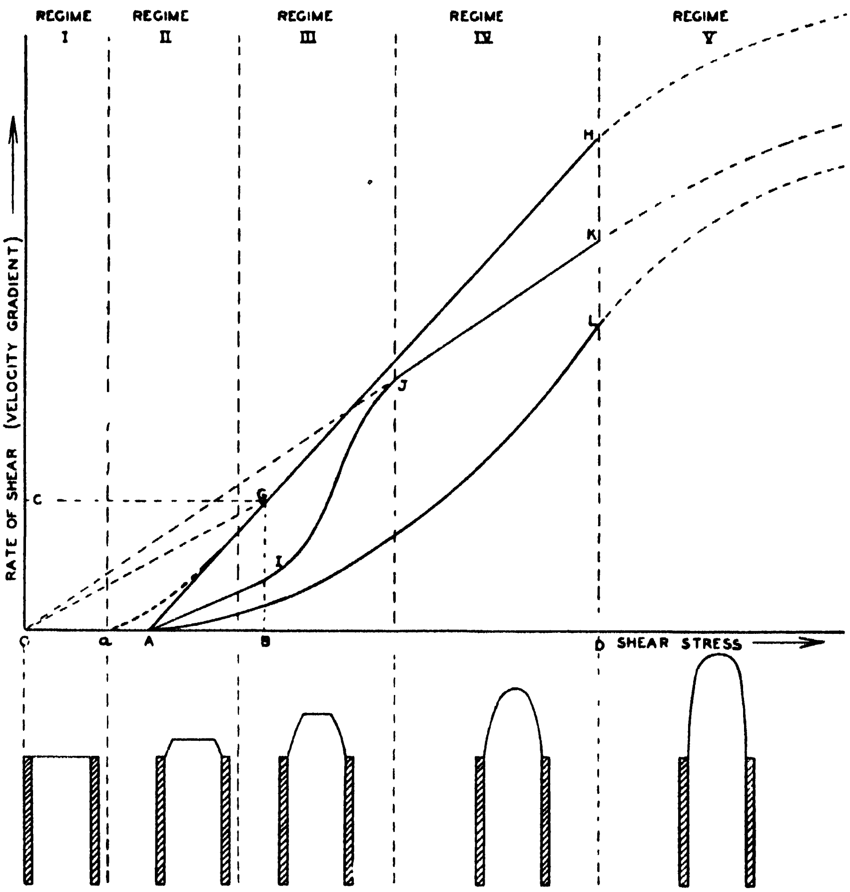

FIG. 1.

Bingham Body

The simplest of the lines on Fig. 1 is the straight line AGH which does not pass through the origin and represents an ideal 'Bingham Body'. The shear stress OA is that required to cause motion to start (referred to by Bingham as the 'yield value' [5, 1919]) and is the shear strength of the material. Any increase in stress above OA causes a proportional increase in the rate of shear.

The equation of this line may be written in the form:

$$\frac{dv}{dx} = \frac{(F-f)}{\eta_s} = \mu(F-f) \qquad \text{(c.g.s. units)}, \qquad (1)$$

where dv/dx = rate of shear or velocity gradient (cm. per sec. per cm. or sec.$^{-1}$),
F = total shear stress (dynes per sq. cm.),
f = shear stress required to start flow (dynes per sq. cm.),
η_s = slope viscosity (poises),
$\mu = 1/\eta_s$ = mobility.

The 'Slope Viscosity' η_s is determined by the slope of the line AH, which is constant, and its numerical value in poises is given by dividing the total shear stress OB minus the shear strength OA by the rate of shear OC in c.g.s. units. The reciprocal of this slope viscosity is referred to by Bingham [4, 1922] as the mobility μ. It should be noted that many writers use the symbol μ for viscosity.

The 'Apparent Viscosity' for the point G is determined by the slope of the line OG joining G to the origin, and its numerical value in poises is given by dividing the total shear stress OB by the rate of shear OC. This is clearly not constant, but for low values of stress it is very large, and when the stress is high it tends to a limiting value equal to η_s. The reciprocal of the apparent viscosity is usually denoted by ϕ, and would be referred to as the apparent fluidity, or simply the fluidity, as distinct from the mobility. These are sometimes referred to as the 'true' viscosity and 'true' fluidity respectively [3, 1916], but these terms are liable to be ambiguous, as, strictly speaking, only Newtonian fluids have a 'true' viscosity or fluidity.

The equation of flow of this ideal 'Bingham Body' (which is really a soft solid) is given below, but in practice a perfectly straight line such as this is seldom realized, and usually there is a certain amount of curvature at the bottom end so that it meets the stress axis at a point such as a. This point is often rather indefinite and may be found to be practically at the origin O, if small enough rates of flow can be measured. The chief causes of such curvature are seepage of the mother liquor through the interstices of the solid particles which do not themselves move, and slippage between the main body of the liquid and the wall of the tube or vessel containing it. This slippage may be due to lack of adhesion with the wall, or, as pointed out by Bingham, to a liquid of different fluidity existing near the wall. It is often also affected by a change in the roughness of the surface as effected by etching [7, 1929]. These effects may be considered to be minor modifications to the simple case and do not alter the general classification.

A notable example of slippage due to different conditions existing at the walls is the flow of foams of gas in oil when the gas/oil ratio is high (i.e. 2:1 and over).

Other Types of Liquid

Another type of stress/shear curve is that represented by the curve $AIJK$ known as the Ostwald curve. In this case beyond a fairly definite point J the behaviour of the liquid ceases to be non-Newtonian and the apparent viscosity becomes constant. The lowest section of the curve AI may be straight, and in some cases this straight section may pass through the origin instead of cutting the stress axis at A, in which case the liquid first behaves like a true liquid; then some structural change takes place due to the mechanical forces, and when the change is complete at the point J the liquid again behaves like a true liquid, but of a lower viscosity. This type of curve was predicted by Wo. Ostwald, and is found to apply to certain types of drilling mud.

Another type of stress/shear curve is that represented by the curve AL which shows a continuous curvature over the experimental range, and which may or may not pass through the origin. In the case in which it passes through the origin the equation of the line may be represented approximately by an equation of the type

$$\frac{dv}{dx} = aF^n, \qquad (2)$$

where n and a are constants and n is greater than 1. With an equation of this type the calculation of flow in pipes is simple, and it may be useful in practice to use such an approximate equation for simplicity. Some types of waxy oils and waxes near their melting-point have roughly this type of stress/shear curve.

As has been pointed out by Reiner [15, 1934], equations of this type cannot be accurately true, since as F becomes infinitely large the apparent viscosity tends to zero. This is, however, no objection when the equation is applied to the approximate solution of practical cases.

Laminar Flow of Non-Newtonian Liquids in Circular Pipes

The flow of liquids having the stress/shear curves shown in Fig. 1 may be divided into five régimes after Merkel [13, 1934], and the velocity distribution over the cross-section of a pipe is illustrated for each.

Consider a circular pipe of radius R and length L full of liquid with a pressure difference P between the two ends. It is easily seen from first principles that the shear stress F_r in any liquid at a radius r is given by

$$F_r = \frac{rP}{2L}. \qquad (3)$$

This shear stress is clearly a maximum at the walls of the pipe, and therefore the value of the shear strength of the material is given by

$$f = \frac{Rp}{2L}, \qquad (4)$$

where p is the pressure required to start flow at the wall.

When the shear stress is less than f, the shear strength of the material (OA in Fig. 1), no flow takes place—régime I. When the shear stress at the wall becomes greater than f the layer in contact with the wall will start to shear and the material in the pipe will start to move forwards as a solid plug—régime II. As the pressure difference is increased the radius r, at which the shear stress F_r is equal to f, will clearly decrease, and this defines the size of the solid plug outside which the liquid flows in telescoping layers—régime III. When the pressure difference becomes very high the radius of the solid plug, r, becomes very small and can be neglected, although theoretically it never quite vanishes. The velocity distribution is then nearly parabolic as in the true viscous flow—régime IV.

To the right of D the curves are shown dashed, as this illustrates the turbulent state previously mentioned—régime V. Curves in this region are not typical of the viscous properties of each liquid, but all tend to show the same curvature, due to the well-known characteristic of turbulent flow, namely, that the pressure drop is nearly proportional to the density and to the square of the velocity, and depends only to a minor extent on the viscosity. The velocity distribution is here of the usual rather flattened form.

It will be observed that except in the turbulent region the curves in Fig. 1 mostly tend to curve upwards, that is, the apparent viscosity decreases with increasing stress; so that

when curves of the type shown in régime V are obtained in a viscometer they should be regarded with suspicion until the absence of turbulence or kinetic energy effects can be proved.

Flow of a Bingham Body

The equation for laminar flow in a circular pipe of an ideal Bingham body obeying the equation (1) (stress/shear

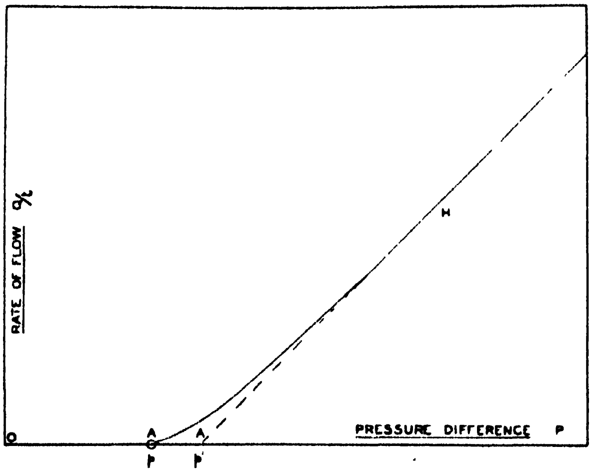

FIG. 2.

curve AGH in Fig. 1) can easily be deduced [3, 1916; 4, 1922] and may be written in the form

$$\frac{Q}{t}=\frac{\pi R^4}{8L\eta_s}\left(P-\frac{4p}{3}+\frac{p^4}{3P^3}\right) \quad \text{(c.g.s. units)}, \tag{5}$$

where Q/t = rate of volume flow in the pipe (c.c. per sec.),
R, L = radius and length of pipe (cm.),
P = total pressure difference over length L (dynes per sq. cm.),
p = pressure difference required to start flow (dynes per sq. cm.).

Now $p = 2Lf/R$ from equation (4), and if this substitution is made in equation (5) we get

$$\frac{Q}{t}=\frac{\pi R^4}{8L\eta_s}\left(P-\frac{8Lf}{3R}+\frac{16L^4f^4}{3R^4P^3}\right). \tag{6}$$

It can be seen from equation (5) that when P is large compared with p the last term becomes very small, and the equation gives a straight line which, if extrapolated back to $Q/t = 0$, would cut the P axis at $4p/3$, while the curve itself cuts this axis at p. This is illustrated by curve AH in Fig. 2, in which the axes are rate of flow and pressure-difference respectively, and it will be noted that the shape of this curve is not quite the same as the stress/shear curve, AGH in Fig. 1, from which it is derived. The distance OA in Fig. 2 represents the pressure p required to start the flow, and the straight part of the curve at H when extrapolated to the pressure axis cuts it at A', the distance OA' representing a pressure p', say.

As mentioned above, according to equation (5) the value of p' is given by

$$p = \tfrac{3}{4}p', \tag{7}$$

but in practice this relation is seldom found to be true, as indicated above in connexion with the point a in Fig. 1. With waxy oils, for instance, p is often rather indefinite and less than $\tfrac{3}{4}p'$. However, the curves for waxy oils generally become quite straight above about $2p'$ and the value of p' is quite definite.

A typical set of consistency curves for a waxy oil at different temperatures is shown in Fig. 3. In this figure, instead of plotting the rate of flow Q/t against the pressure gradient P/L directly from the measurements of flow in the jet of the viscometer or in a pipe, $4Q/\pi R^3 t$ has been plotted against $RP/2L$, which is the shear stress at the wall. We shall now obtain exactly the same curve for the same liquid regardless of the dimensions of the pipe in which the experiment is made, and the curve so obtained is then directly applicable to flow in any pipe, provided that laminar flow is maintained. Curves plotted in this way are known as *Consistency Curves.* These will clearly be exactly similar in shape to the corresponding flow curves plotted as in Fig. 2, and therefore in the case of a Bingham body, as mentioned above, the consistency curve will be slightly different in shape from the stress/shear curve, quite apart from any curvature of the latter which may be observed in practice.

The consistency curves of Newtonian liquids are all straight lines passing through the origin, and in this case the stress/shear and consistency curves are similar in form. The velocity distribution in a circular pipe is then parabolic as required by Poiseuille's law, and $4Q/\pi R^3 t$ is then the rate of shear at the wall. The absolute viscosity is therefore given by the slope of the line, thus:

$$\eta_s=\frac{RP/2L}{4Q/\pi R^3 t}=\frac{\pi R^4 Pt}{8LQ}, \tag{8}$$

which is an expression of Poiseuille's law.

It should be noted that Q should always be in the same units as R^3 and t should be in seconds. The ordinates of all consistency curves will then be in the same units, namely, reciprocal seconds.

The static shear strength of the waxy oil shown in Fig. 3 curve aH at a temperature of 51·5° F. is clearly given by the value of $RP/2L$ at the point a, namely, 70 dynes per sq. cm. or 0·001 lb. per sq. in., and in this case p is less than $\tfrac{3}{4}p'$ and cannot therefore be used in equation (5).

It is possible to make use of the much more definite value of p' to calculate what may be called the 'Dynamic Shear Strength' f' from the theoretical relations of equations (4) and (7), thus:

$$f'=\frac{3Rp'}{8L}. \tag{9}$$

If this value is substituted for f in equation (6), or, what is exactly equivalent, if $\tfrac{3}{4}p'$ is substituted for p in equation (5), we shall get a close approximation to the experimental curve at all except low rates of flow. This is shown in Fig. 3, curve DH. The value of $RP/2L$ at the point A is the dynamic shear strength of this waxy oil, and it is the static shear strength of the ideal Bingham body which is most nearly equivalent to the waxy oil under consideration. This curve is one which will always give a pressure drop on the safe side.

A simpler approximation to the behaviour of an oil of this type which is sometimes useful is the straight line $A'H$ which is obtained by making these substitutions in equations (5) and (6) and ignoring the last term in the brackets. Equation (5) then becomes

$$\frac{Q}{t}=\frac{\pi R^4}{8L\eta_s}\left(P-p'\right). \tag{10}$$

The independence of the dimensions given by the method of plotting shown in Fig. 3 applies to all types of characteristic curve, provided there is no slippage at the walls [3,

1916; 7, 1929]. This type of flow may occur between régimes I and II, as discussed by Buckingham [8, 1921], in which the material moves as a solid plug, lubricated by a very thin layer of fluid which adheres both to the wall of the tube and the surface of the plug. This fluid film may have quite different properties to that composing the plug, and the motion is usually characterized by the velocity of motion being proportional to the applied pressure.

Equation (4) has been given by Buckingham [8, 1921] with an additional term taking slippage at the walls into account, owing to the existence there of a thin film of thickness e of different viscosity η', thus:

$$\frac{Q}{t}=\frac{\pi R^4}{8L\eta_s}\left(P-\frac{4p}{3}+\frac{p^4}{3P^3}\right)+\frac{\pi R^3 eP}{2L\eta'}. \tag{11}$$

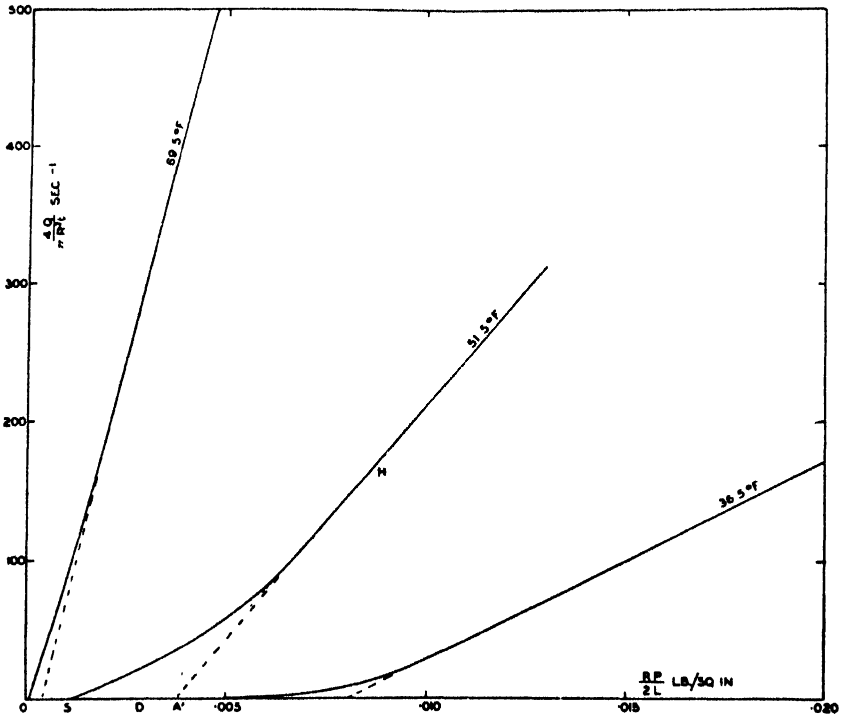

FIG. 3.

When η' is very much lower than η_s, as is the case with some muds, the surface is 'slippery'. The difficulty in the practical application of this equation is of course in determining the value of η' and the thickness e. Keen [10] adds another term to this equation to account for the shear strength of the film at the wall by writing $(P-p')$ for P in the last term of Buckingham's equation.

Flow of Other Types of Liquid

There is no simple general equation of flow in pipes for a liquid having the characteristics of an Ostwald curve (*AIJK* in Fig. 1), and in such a case the best that can be done is to approximate by means of the simpler types of equation over restricted ranges. For instance, Poiseuille's equation can be used at the higher rates of flow above the point J in Fig. 1 and also in the lowest section below the point I if the line goes through the origin, or the equation for a Bingham body if it does not, as shown in Fig. 1.

The equation of flow is, however, easily derived for a stress/shear curve of the general type *AL* in Fig. 1, but passing through the origin instead of the point A, obeying equation (2) when n is 2, i.e. when

$$\frac{dv}{dx}=aF^2,$$

and the equation for flow in a circular pipe may be written in the form

$$\frac{Q}{t}=\frac{a\pi R^5P^2}{20L^2}. \tag{12}$$

This equation may be useful in cases where the stress/shear curve may be approximately represented by this special case of equation (2). It will be noticed that these equations indicate that the form of the consistency curve representing flow in a pipe in this case is identical with the stress/shear curve itself, i.e. rate of movement is proportional to the square of the force causing the movement.

Slope Viscosity of Waxy Oils.

The shear strength of a waxy oil disappears above a certain temperature, owing to the wax melting or going into solution, and above this temperature the oil becomes a true Newtonian liquid with a unique value of the viscosity at any temperature. In the case of the oil shown in Fig. 3 this temperature is about 80° F. Above this temperature the viscosities plotted on the A.S.T.M. chart (A.S.T.M. Viscosity Temperature Chart, Tentative Standard D 341–32T) lie on a straight line, but below this temperature the slope viscosities will not lie on the extrapolation of this straight line, but will lie above it on another line, often nearly straight, which cuts the true viscosity line at the transition temperature. The relation between these lines is illustrated by the curve *ABE* in Fig. 4 which applies to the oil shown in Fig. 3.

If the same oil has had a different thermal history, the slope viscosity line and the transition temperature will both be different, as indicated in curve *CDE* in Fig. 4.

Turbulent Flow of Non-Newtonian Liquid in Pipes

Practically all experimental work on non-Newtonian liquids has been confined to laminar flow, and there has apparently been no published work on the conditions governing the change from laminar to turbulent flow. As has been mentioned above, there is no doubt that when the rate of flow of such liquids is increased beyond a certain critical velocity the flow changes to the turbulent condition very much as in the case of Newtonian liquids. It may also be safely assumed that the change from critical to turbulent flow will take place when the 'Reynolds number', vDp/η (see article [17]), reaches 3,000 or thereabouts. The difficulty is, of course, to assign the correct value to the viscosity in the case of a liquid whose apparent viscosity has no definite value. When treated strictly the problem may be insoluble, but from a practical point of view some means of approxi-

mating to the correct value is very useful. Another point of doubt in evaluating the Reynolds number is in the value for D, due to the possibility that when turbulence starts it may not extend over the whole of the cross-section, but may be confined to an annulus near the wall.

Two cases have to be considered:

(1) Consider a Bingham body with a comparatively high shear strength and relatively low slope viscosity flowing in a large-diameter pipe. It is quite possible that turbulent

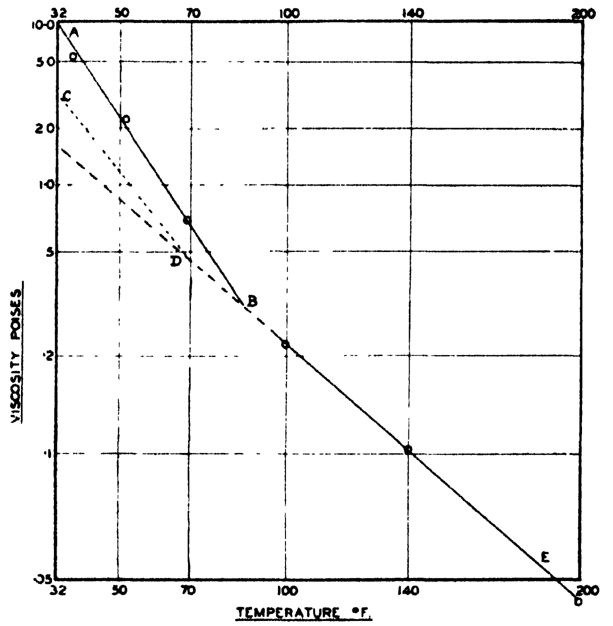

FIG. 4.

conditions may occur during régimes II or III in Fig. 1 while the solid plug still occupies a substantial fraction of the cross-section. As the shear strength is substantial, the solid plug may resist being broken up by the eddies in the outer annulus, in which case the Reynolds number must be calculated for the annulus only, remembering that the hydraulic mean depth in this case is $(R^2-r^2)/2R$, due to the motion of the solid plug.

(2) A somewhat similar condition may perhaps exist even when the solid plug is absent or negligibly small, particularly in the case of a liquid of the type of curve AL in Fig. 1. In such a case the apparent viscosity is very much higher towards the centre of the pipe than near the walls, owing to the reduced shear stress towards the centre, so that here also turbulent flow may take place in an annular region while laminar flow persists in the central core.

These possibilities undoubtedly add to the difficulties of interpretation of practical observations, but it is useful to remember that the velocity distribution in normal turbulent flow is very flat from the centre to about ¾ of the radius, with the result that the existence of a central solid plug will make little difference to the distribution of velocity for a given average velocity or rate of volume flow.

These considerations suggest that the change from laminar to turbulent flow will take place more gradually than with Newtonian liquids and that it is an extremely complex phenomenon. Until a great deal more work on the subject has been done only an outline of the factors involved can be given.

From the considerations given above it is clear that during turbulent flow the total pressure drop in a pipe cannot be obtained by adding the pressure required to start the flow of a Bingham body to the fluid friction, as proposed by Herrick [9, 1932].

Merkel [13, 1934] gives a family of curves showing the pressure drop plotted against the velocity for various sewage sludges flowing in a pipe 20 cm. in diameter. In this case the turbulence limit on these curves corresponds to a Reynolds number of about 3,500 calculated from the apparent viscosity and the full pipe diameter. The flow curves of these sludges bend over gently beyond the turbulence limit, as indicated in régime V in Fig. 1, indicating that in this case turbulence sets in gradually.

In the present state of knowledge it is impossible to calculate the pressure drop in this transitional region between laminar and turbulent flow, and it is only when turbulence has been thoroughly established that the pressure drop can be calculated with reasonable certainty as for an ordinary liquid, and then only when two conditions are fulfilled:

(1) The calculated shear stress at the walls $RP/2L$ must be high enough for the curvature and the shear strength effects near the origin of the consistency curve to be relatively unimportant.

(2) The calculated Reynolds number must be several times the critical value, i.e. 10,000 or over.

If the first condition is fulfilled, the viscosity to be used in the calculation of the Reynolds number has a fairly definite value, and if the Reynolds number is high enough, its exact value is of minor importance in determining the friction factor. Unfortunately these conditions are seldom fulfilled with liquids of the type under discussion, and it is rare for the operating point to be far off the bend of the consistency curve or for the Reynolds number to be much above the critical value.

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ARTICLE

BEALE and DOCKSEY. The Laws of Fluid Flow in Pipelines.

HEAT LOSS FROM BURIED OIL PIPELINES

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Introduction

THERE are two general cases in oil transportation in which means of estimating loss of heat from buried pipelines are required. When a highly viscous oil has to be pumped, the obvious method of reducing the pumping pressures is to heat the oil so as to reduce its viscosity. Since, in such cases, the flow is stream-line, the pressure drop for a given pumping rate is proportional to the mean effective viscosity in the pipe. When the pipeline is long it may be necessary to lag the pipe with heat-insulating pipe-covering so as to reduce the heat loss, but usually the pipe is simply buried in the ground with any covering required to resist corrosion, and the insulating properties of the ground and corrosion covering is relied on to maintain the temperature of the oil at the far end of the line above the necessary minimum value.

The converse case occurs with pipelines across deserts where it is required to make use of the crude oil in the pipeline to cool the circulating water of the Diesel pumping sets situated at intervals along the line where water is scarce. In these cases the heat from the jackets of the engines, as well as the heat generated in the line by friction, has to be dissipated from the surface of the pipeline into the ground and eventually, of course, from the surface of the ground to the air in the length of line between pumping-stations.

Here the conduction of the soil must be great enough to prevent the temperature of the oil at the end of any section of the line from reaching too high a value, so as to enable the engine jackets to be kept down to a safe working temperature, even at the hottest period during the summer.

In the present article the flow of heat for the purpose of estimating the temperature of the oil along the pipe only is considered, given the starting temperature and the heat generated by friction at each point along the line; but in the general case, not only does the temperature at each point depend on the heat loss, but the heat generated itself depends on the temperature, so that the complete solution would be extremely complicated.

It is not uncommon for viscous oils to be waxy and to deposit wax on the walls of the pipe as the temperature falls. This introduces a further complication, since the waxy layer increases the friction and, therefore, the heat generated per unit length, and it also constitutes an insulating layer which reduces the heat flow, and both of these effects are difficult to estimate owing chiefly to the fact that the rate of deposit of wax is hard to predict.

General Nature of the Problem

In the simplest case of heat flowing from a hot pipe to the surface of the ground at a lower temperature, the heat passes successively from the body of the oil to the pipe wall, through this into the ground. Here the lines of flow leave the pipe surface more or less radially, but soon those leaving the bottom and sides of the pipe bend upwards and eventually reach the surface of the ground practically vertically. This is illustrated in Fig. 1, which shows the lines of heat flow (solid) and the isotherms (dashed) which are both parts of circles and cross at right angles.

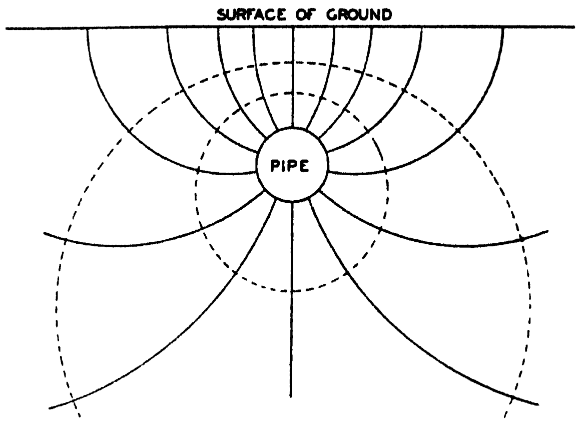
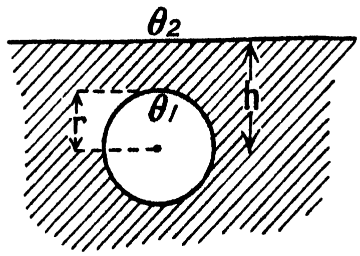


FIG. 1.

At the surface of the ground the heat is dissipated, chiefly by convection to the air. Strictly speaking, each of these constitute a resistance to flow of heat, but in practice all of them can be neglected, except the insulating effect of the ground. If we consider only the condition when the heat flow has become steady, that is, a long time after the start when temperature conditions have all become constant, the calculation of the resistance of the ground round a buried pipe is quite simple.



The equation for the steady rate of heat flow Q between a long cylinder (of radius r and length L) and a plane surface at a distance h from the axis of the cylinder is obtained by solving the equation

$$\frac{\partial^2\theta}{\partial x^2}+\frac{\partial^2\theta}{\partial y^2}=0$$

with the appropriate boundary conditions. The exact solution is:

$$Q=\frac{4\pi LK(\theta_1-\theta_2)}{\log_e\left(\dfrac{h+\sqrt{(h^2-r^2)}}{h-\sqrt{(h^2-r^2)}}\right)}, \tag{1}$$

where K is the conductivity of the medium, supposed of infinite extent and uniform in conductivity.

This may be written in the more usual approximate form:

$$Q \doteqdot \frac{2\pi LK(\theta_1-\theta_2)}{\log_e(2h/r)}. \quad (2)$$

These equations are for any set of self-consistent units. For instance, the units on the c.g.s. ° C. system and on the British Foot-Pound-Hour-° Fahrenheit are as follows:

	c.g.s.	*British*
Q = rate of heat flow	g.-cal./sec.	B.Th.U./hour
$\theta, \theta_1, \theta_2$ = temperature .	° C.	° F.
L, r, h, x, y = length, radius, depth, etc.. .	cm.	ft.
K = thermal conductivity . . .	g.-cal./sec. sq. cm. ° F. for 1 cm. thickness	B.Th.U./hr. sq. ft. ° F. for 1 ft. thickness

The effect of the resistance to heat flow from the surface to the atmosphere may be allowed for by increasing the depth h by a small amount in the calculation; similarly, the insulating effect of pipe-covering or wax deposit inside the pipe could be closely represented by a reduction in the effective value for r.

Given the dimensions, the conductivity of the earth, and the temperature of the pipe and of the surface of the ground, the heat flow can be calculated quite simply for the steady state as described; but in practice the problem is somewhat complicated by the fact that the temperature of the surface of the ground is not constant, and daily and annual temperature waves travel downwards from the surface.

At first sight this circumstance would appear to make the solution extremely complicated, but it can be shown that the actual flow of heat from the pipe at any instant is that given by calculating the flow of heat for the steady state conditions, as described above, provided that, in place of the actual temperature at the surface of the ground at that instant, the temperature that the ground at the depth of the centre of the pipe would have had at the same instant, supposing that the pipe had not been either absorbing or giving out heat is used. This is not quite precisely true, but is quite close enough for all practical purposes.

In other words, in order to calculate the rate of heat loss from the pipe at any moment the temperature of the ground at the depth h in the undisturbed ground must be estimated, either from earth-temperature records for that time of the year or by calculation from the surface-temperature records as indicated below, and then calculate Q by equations (1) or (2), using this temperature in place of θ_2.

As is well known, the range of temperature variation decreases as the depth below the surface increases, i.e. the maximum temperature in summer is lower and the minimum temperature in winter is higher. Clearly, the resistance to heat flow increases as the depth is increased; therefore, in the first general case, where the highest minimum temperature is wanted, the deeper the pipe is buried the better, but in the second general case, where the lowest maximum temperature is required, these two effects tend to compensate, and there may be an optimum depth which gives the lowest maximum temperature.

The equation giving the amplitude of the temperature variation at any depth when the surface temperature varies sinoidally [1] is for self-consistent units:

$$\theta_x = \theta_0 e^{-\sqrt{(\pi x^2/Ta)}} \quad (3)$$

where *c.g.s. units*

θ_0 = amplitude (or $\frac{1}{2}$ range) at the surface · ° C.
θ_x = " " " a depth x · ° C.
T = periodic time · · · · · · sec.
x = depth cm.
a = thermal diffusivity = $K/C\rho$
$= \frac{\text{conductivity}}{\text{specific heat} \times \text{density}}$ · · · cm.²/sec.

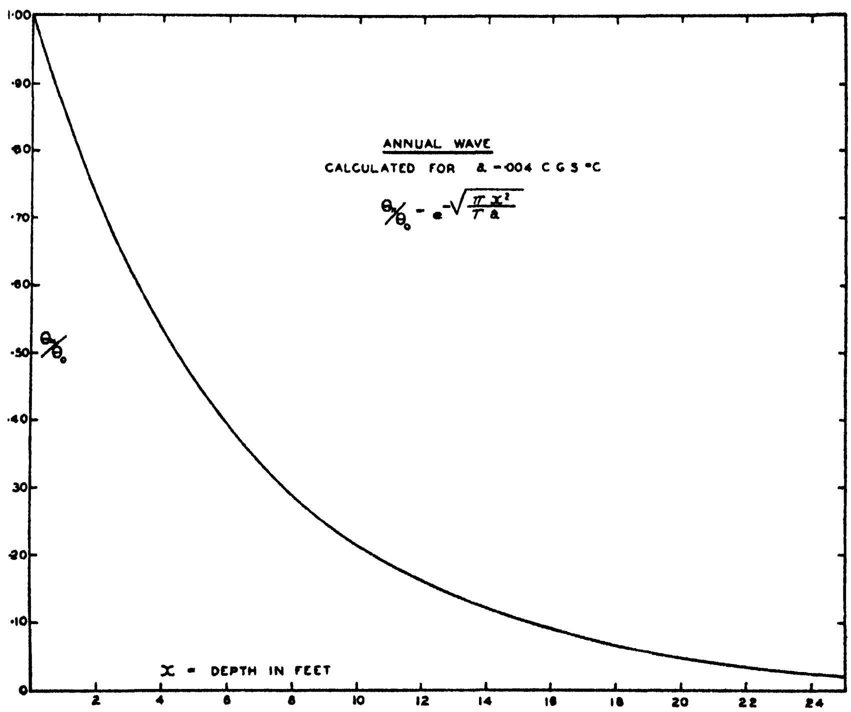


FIG. 2.

The daily temperature wave may be neglected, since its amplitude at a depth of only 1 ft. is very small. The annual variation in surface temperature may be represented sufficiently closely by a sine wave, and the amplitude of the annual wave, calculated from the equation for a diffusivity of 0·004 c.g.s. units, is shown in Fig. 2 as a fraction of the amplitude at the surface plotted against the depth below the surface. From this curve the temperature range at any depth for other values of diffusivity can easily be obtained from the fact that corresponding temperatures occur at depths proportional to $1/\sqrt{a}$. The amplitude of the daily wave may be read from the curve by dividing the depth scale by $\sqrt{365}$.

The above equation may be used for estimating the temperature of the earth at the depth of the pipe if no earth-temperature records are available by choosing a suitable

value for the diffusivity. Alternatively, it may be used to estimate the diffusivity, and thence (with suitable assumptions for the specific heat and the density) the thermal conductivity from temperature-depth records.

The product of the specific heat and the density will be referred to as the 'Volumetric Heat' of the substance, since it is the heat capacity of unit volume. It so happens that the numerical value of the volumetric heat for different soil-forming materials does not differ very greatly, so that it is possible to make quite a reasonably close estimate of its value in any given case, particularly if the bulk density and moisture content are known.

As is well known, the time at which the temperature reaches a maximum varies with the depth, the phase shift at a depth x is equal to $-\sqrt{(\pi x^2/Ta)}$ radian, therefore

$$\text{the time lag at a depth } x = \sqrt{\left(\frac{Tx^2}{4\pi a}\right)} \qquad (4)$$

This formula, like equation (3), is for self-consistent units and any system can, of course, be used. For instance, if T is in hours and x in feet, then the thermal diffusivity a must be expressed in (ft.)^2 per hour.

This expression for the time lag may be used in the same way as equation (3) for estimating the diffusivity of the earth from the earth-temperature records.

Thermal Data for Soil

As previously mentioned, the major resistance to heat flow is in the ground itself, and therefore the effective thermal conductivity of the soil in the neighbourhood of the pipe is one of the most important factors. As is well known, the thermal conductivity of all granular solids depends very largely on their moisture content as well as on their composition and consistency.

The variation of thermal conductivity with water content for four materials, investigated by Patten [2, 1909], is shown in Fig. 3. The mechanical analysis of three of these were approximately as follows:

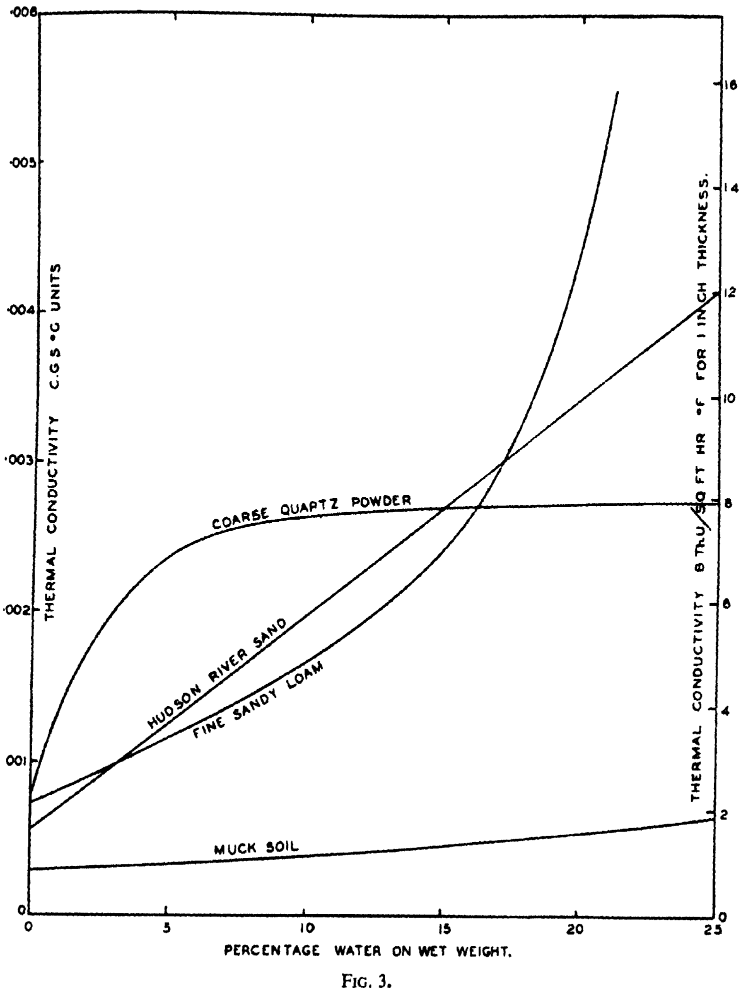


FIG. 3.

Particle size		*Coarse quartz powder*	*Hudson River sand*	*Fine sandy loam*
	mm.			
Coarse sand	1–0·5	15	0	2
Medium sand	0·5–0·25	58	1	3
Fine sand	0·25–0·1	26	70	47
Very fine sand	0·1–0·05	1	19	38
Silt	0·05–0·005	..	8	..
Clay	0·005–0	..	2	..

The material described as 'Muck Soil' in Figs. 3 and 4

was quite different from the others and contained a large amount of organic matter. Clearly, very considerable differences are to be expected with soils of such different types, but in all cases the effect of water content is considerable.

The corresponding values of the diffusivity and the volumetric heat (specific heat × density) for these same materials are given in Fig. 4 which was drawn up from Patten's experimental figures. In considering these results, it should be borne in mind that the thermal conductivity of water is 0·0014 c.g.s. units or 4·1 B.Th.U. per hr. sq. ft. ° F. for 1 in. thickness, and its diffusivity is 0·0014 c.g.s. units.

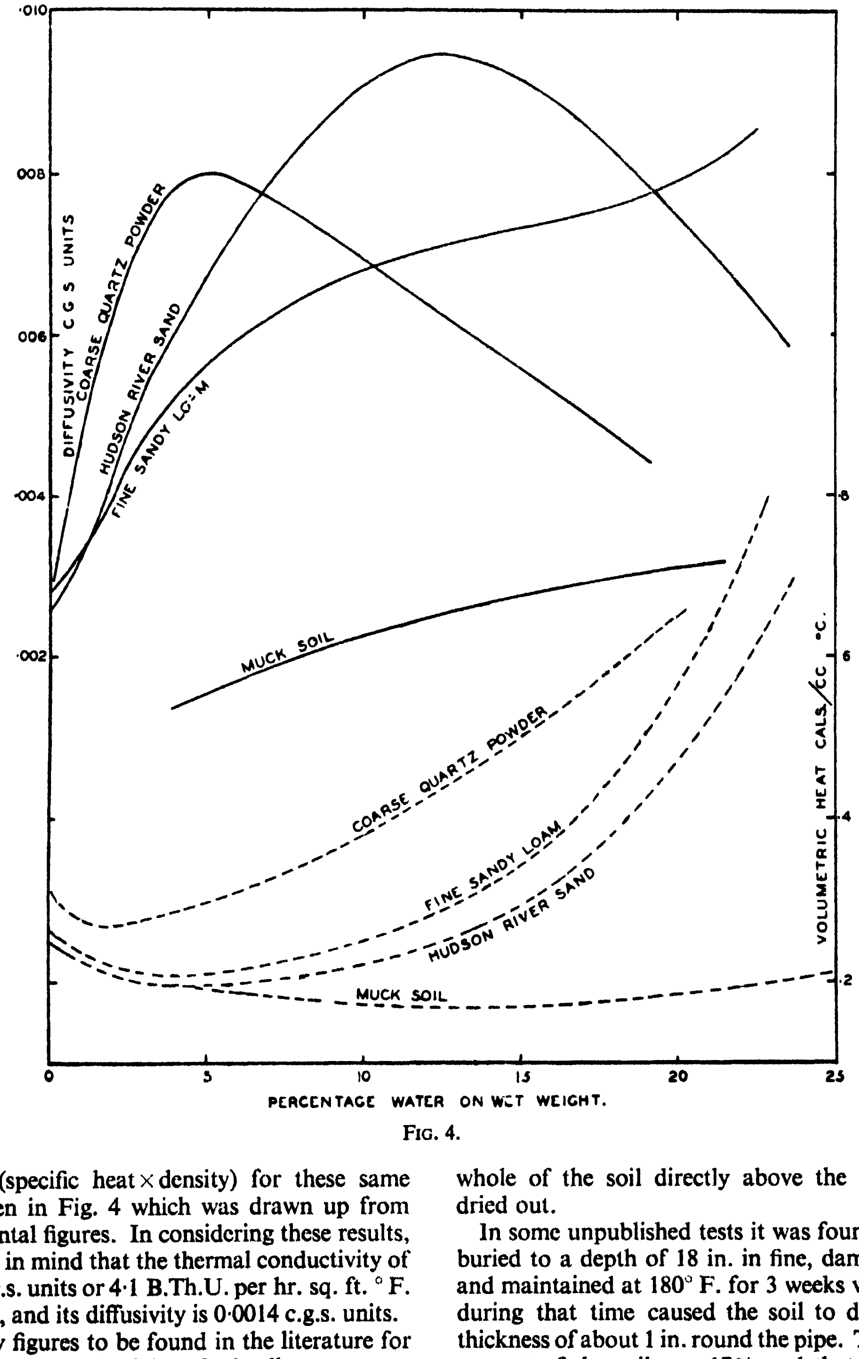


Fig. 4.

There are many figures to be found in the literature for the diffusivity and the conductivity of miscellaneous types of soil and sand, but very often neither the moisture content nor any analysis of the materials are given.

Drying of the Soil

As already mentioned, the thermal conductivity of the ground, when undisturbed by the presence of the pipe, may be estimated from earth-temperature records or otherwise, but when this has been done the drying of the earth round the pipe has to be considered, and there is practically no published information on this subject.

If the temperature of the pipe itself is high and there is little or no rainfall, the soil round the heated pipe will become dried, and form a layer of relatively low conductivity. With a large pipe buried close to the surface the whole of the soil directly above the pipe may become dried out.

In some unpublished tests it was found that a 4-in. pipe buried to a depth of 18 in. in fine, damp soil under grass and maintained at 180° F. for 3 weeks without rain falling during that time caused the soil to dry out to a radial thickness of about 1 in. round the pipe. The initial moisture content of the soil was 17% and that of the dried layer was about 2½% by weight. This drying caused a drop in heat loss to about two-thirds the normal value, the heat loss in both cases agreeing closely with the calculated values based on the conductivities from Fig. 3 for fine, sandy loam. After heavy rainfall averaging nearly 1 in. per 24 hours for several days, the moisture content rose to 22% and the effective conductivity rose to 16 B.Th.U. per hr. sq. ft. ° F. for 1-in. thickness or 0·0055 c.g.s. units. The rate of drying

at lower pipe temperatures is naturally very much less, and in these tests the drying at 85° F. was not appreciable.

These results are not necessarily typical of the effect to be expected in other circumstances, but indicate the general trend. For instance, the natural drying of the soil in dry, hot climates should also be taken into account.

Rain-water percolating down to the level of the heated pipe will absorb some heat, but calculation shows that even at the rate of 1 in. of rain in 24 hours this is a small effect compared with the change in conductivity of the soil due to saturation with water.

Calculation for Long Pipelines

A typical application of equation (1) to an oil pipeline is that of calculating the temperature of the oil at the far end of a pipeline after leaving the pumping-station at a specified temperature.

In this case it must be remembered that heat is being generated in the pipeline itself due to the friction loss, and it will therefore first be necessary to make an estimate of this quantity for use in the calculation of the final temperature. This introduces a difficulty because the final temperature depends on the friction, the friction in the pipe depends on the viscosity, and the viscosity of the oil depends on the temperature. With turbulent flow in the pipe this will not present much difficulty, since the friction factor and therefore the amount of heat generated per unit length of the pipe depends but little on the viscosity of the oil. In the case of stream-line flow, however, the friction loss for a given throughput is proportional to the viscosity, and the viscosity changes rapidly with the temperature in the case of heavy oils, which are just those most likely to be in stream-line flow.

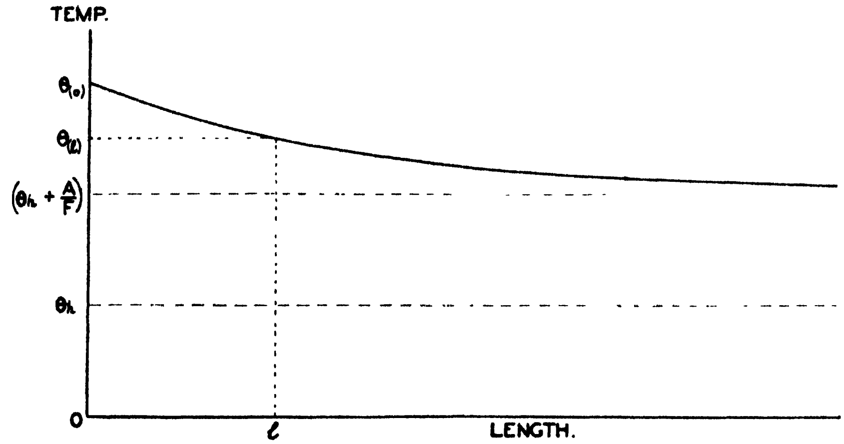


FIG. 5.

A reasonable value for the heat generated per unit length must therefore be taken for use in the following calculation and the true value arrived at by the usual method of successive approximation if necessary.

		c.g.s. units
Let $\theta_{(0)}$ =	temperature of the oil entering the pipeline	° C.
$\theta_{(l)}$ =	temperature of the oil at a distance l from the origin	° C.
θ_h =	temperature of the undisturbed earth at the same depth h as the centre of the pipe	° C.
A =	heat generated per unit time by friction per unit length of pipe	g.-cal./cm. sec. ° C.
F =	coefficient of heat transmission per unit length of pipe	g.-cal./cm. sec. ° C.
	$= \dfrac{Q}{(\theta_1-\theta_2)L}$ from eq. (1)	
W =	heat capacity of the oil flowing through the pipe per unit time	g.-cal./sec. ° C.
	= mass flow × specific heat	

The temperature of the oil after covering a distance l is easily shown to be given by the equation

$$\theta_{(l)} = \left[\theta_{(0)}-\left(\theta_h+\frac{A}{F}\right)\right]e^{-Fl/W}+\theta_h+\frac{A}{F}. \tag{5}$$

It will be noticed that the dimension of A/F is that of a temperature, and self-consistent units must obviously be used; the dimension of the exponent of e is then a pure number with no dimensions. (θ_h+A/F) is the final steady temperature of the oil at the end of a very long pipeline, and the expression in the square brackets is the difference between the initial temperature of the oil and this final steady temperature, this difference falling exponentially along the pipeline. This is illustrated in Fig. 5.

Oil heated at Intervals along a Pipeline

Now suppose the oil is heated at regular intervals along a pipeline so as to reduce its viscosity, or alternatively that we have a series of pumping-stations spaced at equal distances along a pipeline and that the jackets of the pumping engines are cooled by heat exchange with the oil in the pipeline. The temperature of the oil at the end of each section can be calculated by an extension of equation (5).

For simplicity we will take the conditions to be exactly similar at each section of the line, i.e. the distance between stations, the earth temperature, and the temperature rise in the oil at each heat exchanger, &c., are all the same for each section.

Let L = distance between stations,

$\theta_1, \theta_2, \ldots, \theta_n$ = temperature of oil at the *end* of sections 1, 2,..., n, i.e. at distances from the origin of $L, 2L, \ldots, nL$,

θ' = temperature rise in the oil in passing through each heat exchanger situated at the beginning of each section after the first.

Then from equation (5) we obtain

$$\theta_1 = \left[\theta_{(0)}-\left(\theta_h+\frac{A}{F}\right)\right]e^{-Fl/W}+\theta_h+\frac{A}{F}$$

$$\theta_2 = \left[\theta_1-\left(\theta_h+\frac{A}{F}\right)+\theta'\right]e^{-Fl/W}+\theta_h+\frac{A}{F}.$$

$$\therefore\ \theta_n = \left[\theta_{(0)}-\left(\theta_h+\frac{A}{F}\right)\right]e^{-FnL/W}+ +\theta_h+\frac{A}{F}+\theta' e^{-FL/W}\frac{1-e^{-F(n-1)L/W}}{1-e^{-FL/W}}. \tag{6}$$

When n becomes large (perhaps only 4 or 5) the first term in the expression can usually be neglected; in other words, the initial temperature has no influence on the final temperature.

The Iraq Pipeline

A case in point, which is given as an illustrative example for which the calculations discussed above were carried out, is the Iraq pipeline, in which the oil is used to cool the circulating water of the Diesel engines at the pipeline pumping-station.

The Iraq pipeline links Kirkuk via Fatha on the Tigris to Haditha on the Euphrates by means of two lines parallel for a distance of 150 miles, whence one runs WSW. to Haifa in Palestine, and the other line runs due west to Tripoli in French Syria. The pipelines traverse chiefly desert country. Pumping-stations located at from 60 to 95 miles apart, according to the gradients, are equipped with 900 B.H.P. Diesel engine-driven reciprocating pumps. The length of the line from Kirkuk to Tripoli is 531 miles and from Kirkuk to Haifa 617 miles.

Each of the two lines comprising the pipeline system is composed mainly of 12-in. dia. pipe with some 10-in. dia. and buried with a cover of 2 ft. 6 in. of soil above the top of the pipe. The country traversed by pipeline is subjected to extremely wide variations in temperature. Frost may occur over parts of the line during the winter months. In summer time the shade temperature may reach 120° F. with a fluctuation of 40 to 50° F. between day and night. During the winter months there will be heavy rains, followed by continuous dry periods of 6 months or more without any rain.

The cooling of the Diesel engines is carried out by circulating water through the engine jackets and heat exchangers. In the latter the heat of the cooling water is removed by counter-current flow with crude oil in shell-and-tube type heat exchangers. Alternative cooling arrangements by means of a reserve water-supply and small cooling-tower safeguard the system in case of emergency.

On the double line from Kirkuk to Haditha, the point of bifurcating, there are three pumping-stations each equipped with six pumps. The stations between Haditha and Haifa and Haditha and Tripoli are each equipped with three pumps.

If the temperature of the crude oil being pumped is not to rise unduly, heat from the oil will have to be dissipated to the surrounding soil and ultimately to the air. The heat to be dissipated will arise partly from the heat exchanged with the circulating water (equivalent for the line under consideration to a temperature rise of about 7° F.) and partly from friction. If no heat were removed, the temperature rise due to friction between flowing oil and pipe would be about 5·5° F. between successive stations.

The heat to be dissipated from both causes amounts to a little less than 10 B.Th.U. per foot run of pipe per hour. In moist earth or any soil of good heat conductivity it is evident that there would be no difficulty in dissipating this amount of heat, but the problem was to estimate the rate of dissipation under desert conditions.

The calculations are based on the following data:

B.H.P. of Diesel engines	= 900
Length of each line 60 miles	= 96 km.
Pressure at beginning of line 800 lb. per sq. in.	= 56 kg./cm.^{2}
„ „ end „ 50 lb. per sq. in.	= 3·5 kg./cm.^{2}
Velocity of oil in pipeline = 3·5 ft. per sec.	= 106 cm./sec.
Heat set up by friction in the oil	= 540 B.H.P.
	= 1·38 × 10^6 B.Th.U./hr.
	= 1·04 × 10^5 g.-cal./sec.
Hence the heat to be dissipated	= 4·3 B.Th.U./hr. per ft.
	= 1·1 × 10^{-2} g.-cal./cm. per sec.
Heat to be dissipated from jackets	= 2,000 B.Th.U./B.H.P. hr.
	= 1·8 × 10^6 B.Th.U./hr.
	= 1·25 × 10^5 g.-cal./sec.
Temperature rise of the oil due to heat absorption from jackets	= 7° F. = 3·9° C.
Diameter of pipe . . .	= 12 in. = 30·5 cm.
Depth of centre . . .	= 3 ft. = 91·5 cm.

Calculation of the Conductivity of the Ground

For the calculation of the heat loss it was in the first place necessary to know the conductivity of the ground. This could be calculated from a temperature record registered at Mosul at two different depths, namely, 1 ft. (= 30·5 cm.) and 4 ft. (= 122 cm.). The ratio of the amplitude of the temperature variation at these two depths was 1·45 to 1, and by applying equation (3) to this case a value of $a = 0{\cdot}0062$ c.g.s. units is obtained.

The time lag of the temperature wave between these two depths were also used to check this value by means of equation (4). The observed time lag of 21 days leads to a diffusivity $a = 0{\cdot}0064$ c.g.s. units. The mean value used for the calculation of the conductivity was therefore taken to be

$$a = 0{\cdot}0063 \text{ c.g.s. units.}$$

An estimate was then made of the volumetric heat of the soil in this region, and the minimum probable value was 0·3 g.-cal. per c.c. ° C., and the most likely value was taken to be 0·43 g.-cal. per c.c. ° C. This last value, when used in conjunction with 0·0063 c.g.s. units for the diffusivity, leads to a value for the thermal conductivity $K = 0{\cdot}0027$ g.-cal. per cm. sec. ° C.

It is then possible to calculate the coefficient of heat transmission F for use in equation (5).

Instead of using the actual value for the depth to the centre of the pipe, namely, 91·5 cm., the slightly larger value 100 cm. has been used to allow for the finite conductance from the surface of the ground to the air. This allowance of 8·5 cm. of soil of conductivity 0·0027 g.-cal. per cm. sec. ° C. is equivalent to a surface conductance of about 0·0003 g.-cal. per sq. cm. sec. ° C. or about 2 B.Th.U. per sq. ft. hr. ° F., which is a fair value for radiation plus convection in a very slight wind.

The calculation of F in this case from equation (1) gives

$$F = \frac{2\pi K}{\log_e\left(\dfrac{h+\sqrt{(h^2-r^2)}}{h-\sqrt{(h^2-r^2)}}\right)} = 0{\cdot}006 \text{ g.-cal. per sec. cm. } ^\circ\text{C.}$$

The flow of the oil in the pipeline is turbulent and the temperature changes are relatively small, so that there is no doubt about the heat generated by friction in the pipe, and finally the maximum temperature at a depth of 3 ft. at Mosul (which occurs in August) is 33° C.

We have now all the data necessary for the calculation of the maximum temperature in the oil at any pumping-station on entering the heat exchangers.

The numerical data required for equation (6) is as follows:

$$\theta_h = 33^\circ \text{ C.}$$
$$\theta' = 3{\cdot}9^\circ \text{ C.}$$
$$A = 0{\cdot}011 \text{ g.-cal. per cm. sec.}$$
$$F = 0{\cdot}006 \text{ g.-cal. per cm. sec. } ^\circ\text{C.}$$
$$W = 33{,}000 \text{ g. per sec. } ^\circ\text{C.}$$
$$L = 9{\cdot}6\times 10^6 \text{ cm.}$$
$$n = 7.$$

The important station in this case is the last, where any cumulative effects from previous stations will be felt. Making these substitutions in equation (6), we get

$$\theta_7 = [\theta_{(0)}-34{\cdot}8]e^{-12\cdot 2}+33+1{\cdot}8+3{\cdot}9\times e^{-1\cdot 75}\frac{1-e^{-10\cdot 5}}{1-e^{-1\cdot 75}}\cdot$$

Since the first term here is quite negligible the initial temperature $\theta_{(0)}$ does not affect the final temperature $\theta_{(7)}$, which is found to be:

$$\theta_7 = 33+1{\cdot}8+0{\cdot}9 = 35{\cdot}7^\circ\ \mathrm{C}.$$

It will be seen, therefore, that the cumulative effect of the successive rises of temperature at each station is only 0·9° C. (= 1·5° F.). It was concluded from these calculations that oil-cooling of the engines would be practicable.

REFERENCES

1. See INGERSOLL and ZOBEL. *The Mathematical Theory of Heat Conduction.*

2. PATTEN. U.S. Department of Agriculture, Bureau of Soils Bulletin no. 59 (1909).

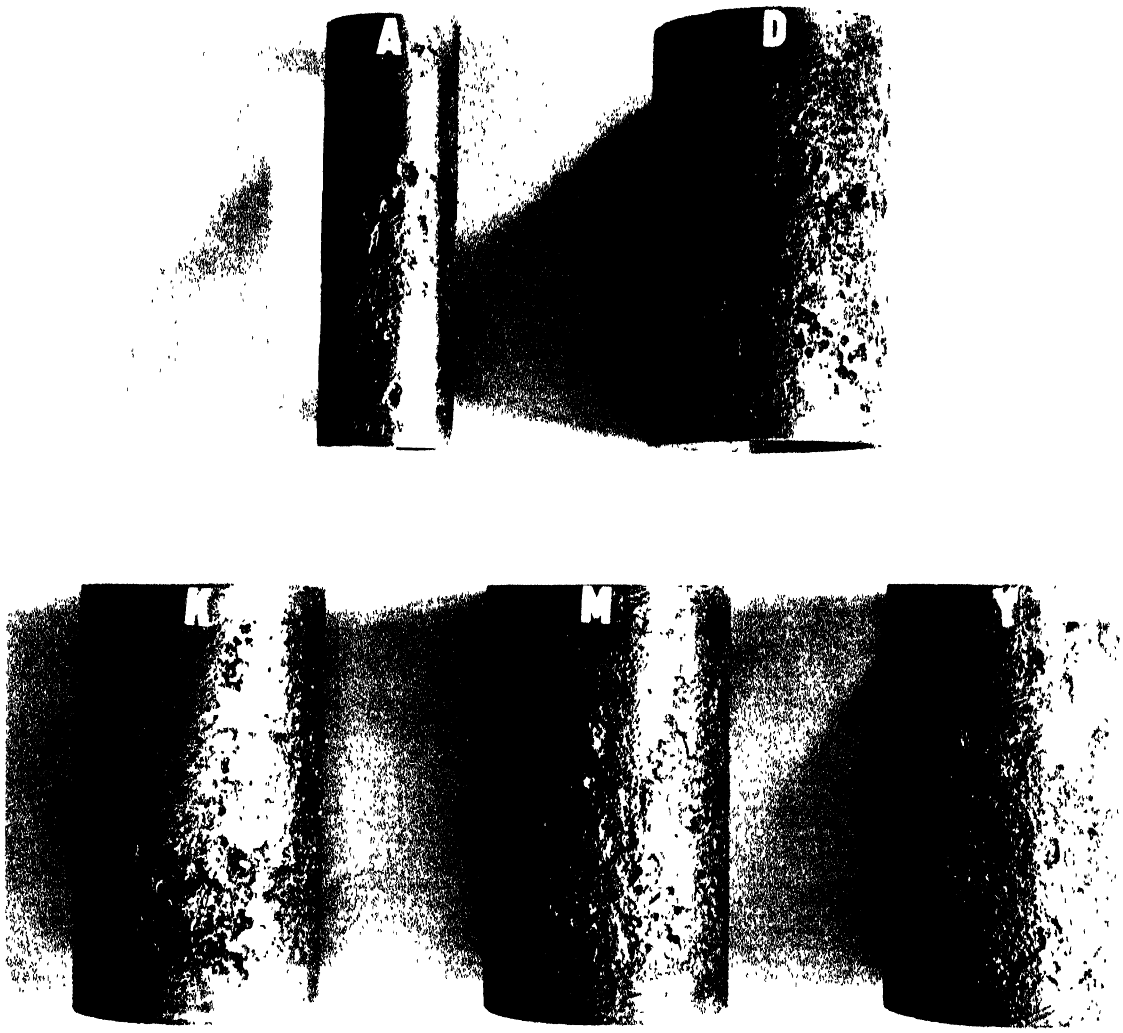


FIG. 1 *A*, Pure open-hearth iron, *D*, wrought iron, *K*, open-hearth steel, *M*, Bessemer steel, *Y*, open-hearth steel 0.2 copper exposed to Hempstead silt loam for approximately 12 years Note similarity of corrosion of the different materials

THE CORROSION AND PROTECTION OF PIPELINES IN THE UNITED STATES OF AMERICA

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Introduction

THE theory of underground corrosion upon which this article is based postulates a difference of electrical potential between two points on the surface of the pipe. Differential aeration is shown to be an important, although not the only, cause of the difference of potential. Imperfections or impurities in the metal are not the controlling factors in underground corrosion, since usually specimens of different ferrous materials in the same soil corrode similarly. Since the same material corrodes differently in different soils, it is evident that the soil is the controlling factor in underground corrosion.

The corrosiveness of the soil depends largely on the character of the corrosion products which are formed in it. Non-uniformity of action is one of the important characteristics of corrosion. This makes the determination of the condition of an underground pipeline difficult.

Since it is impracticable to uncover the entire line, its condition must be estimated from data on the condition at a relatively small part of its area. The data can represent the condition of the line as a whole only if they conform to the rules which govern the sampling of other materials, i.e. they must represent all the variables both as to quality and as to quantity. Three sources of information are available—reconditioning records, leak records, and inspections made at selected points on the line. The first two assume that no deterioration has occurred on portions of the line for which there is no corrosion record. The third method is satisfactory only if the points of inspection adequately represent all conditions throughout the length of the line.

In order that the most probable condition on a section of line within one type of soil be properly estimated, it is necessary to increase the average pit depth observed on a short section of the line by a factor representing the relation of pit depth to area, since it has been found that the larger the area inspected the deeper the deepest observed pit. This fact has been expressed by a pit-depth area formula.

In many soils the rate of corrosion decreases with the time of exposure. For such soils the maximum pit depth on a section of a line is not proportional to the time the line has been in service, but is represented by a curve. Since the equation representing the relation of pit depth to time involves two factors which are functions of the soil, it is not possible to estimate the life of a pipeline from observations of its condition after only one period of exposure.

Early technical methods for determining the corrosivity of soils proved inadequate because the relation of soils to corrosion was not understood. Recent investigators by studying the relation of soils to the character of corrosion products which they produce appear to be somewhat more successful. While the determination of the character and quantity of soluble salts in a soil is suggestive of its corrosiveness, for soils in which these salts are absent or very limited in amount the determination of soil acidity is of value.

Many of the most used methods for estimating soil corrosivity are based on measurements of soil resistivity, although some of these involve the effects of polarization also.

Three methods may be employed to prolong the life of pipe—the use of corrosion-resistant materials, protection of the pipe by coatings, or modification of the soil surrounding the pipe.

Inexpensive ferrous alloys have shown no marked superiority over ordinary steel, except, perhaps, under a limited number of soil conditions. Bituminous pipe coatings are easily injured and require more care in application and handling than they have frequently received. They reduce the corroded area, and in most cases the rate of corrosion, but they rarely prevent all corrosion for more than a very few years. Their purpose, however, is to reduce the operating cost of the pipeline, and this may be accomplished by an imperfect coating.

Soil treatments by chemicals have been proposed but not extensively used. Occasionally a pipeline operator has replaced a corrosive soil along a short section of line by surrounding the pipe with a non-corrosive soil. Both sand and clay have been used for this purpose. The choice should be governed by local conditions.

I. Principles of Underground Corrosion

That most, if not all, corrosion at normal temperatures is an electrochemical phenomenon has been quite well established. It has been necessary, however, to modify and interpret the original electrochemical theory of corrosion very considerably in order to apply it to the entire field of corrosion. In general, the theory postulates that there is a migration of electrically charged particles of the corroding material from the surface of the material because of a difference of electrical potential between the corroding area (the anode) and some other area on or in metallic contact with the corroding structure. The causes of this difference of potential and the way in which the currents resulting therefrom are modified form the basis for the discussions of the theory of corrosion.

A difference of potential between two points on the surface of a buried pipe may arise from any one of several sources, or from a combination of several causes. For a long time pitting was attributed either to an electrical current from some outside source or to non-homogeneous material. More detailed observation of conditions under which underground corrosion has occurred has led to the conclusion that other causes of corrosion are more common and more important. Perhaps this has been most conclusively demonstrated by the soil-corrosion investigation of the National Bureau of Standards. In this investigation specimens of commercially pure open-hearth iron (total impurities about 0·17%), wrought iron, Bessemer steel, open-hearth steel, open-hearth steel containing 0·2%

copper, and three varieties of cast iron were buried in 47 representative soils. Care was taken to avoid any possibility of electric currents from street railways or other outside sources. Approximately 6,000 specimens were buried, a number sufficient to permit the calculation of the precision of the results and to allow the elimination of specimens which for any reason appeared to be abnormal.

Since each test site was explored electrically and no location accepted where there was a possibility of stray currents in the earth, the corrosion observed in the specimens could not have been caused by stray currents. Moreover, an examination of the distribution of the corrosion with respect to the positions of the specimens in the trench indicates that they were not affected by stray currents. It was found that as a rule all the wrought specimens in the same trench corroded similarly with respect to losses in weight, depths of the deepest pits, and distribution of the corroded areas. From this it follows that the cause of the corrosion did not lie within the specimens, since they differed greatly in composition and were furnished by several independent pipe mills. Both impurities and composition of the material were thus eliminated as primary causes of underground corrosion. Furthermore, it was observed that in some soils all materials corroded much more seriously than in other soils. It is evident, therefore, that the chief causes of corrosion are associated with soils or soil conditions. The similarity of corroded specimens of different materials exposed to the same soil is shown in Fig. 1, while Fig. 2 illustrates the variation in the corrosiveness of different soils with respect to the same material. The conclusion was reached that the corrosion underground depends primarily on soil conditions and that all the commonly used ferrous pipe materials behave similarly when exposed to the same soils. The importance of these conclusions will be discussed later.

Other investigations of the Bureau of Standards have indicated a number of soil properties and soil conditions which influence the rate of corrosion of ferrous materials. That differential aeration is a common cause of a potential difference was pointed out by Aston in 1916 [2], and a little later by Evans.

Oxygen has frequently been mentioned as essential to corrosion under most conditions, and since the corrosion products are usually oxides it has frequently been assumed that corrosion is the result of an attack on the iron by oxygen, i.e. that corrosion is due to direct oxidation of the metal. While direct oxidation occurs when iron is exposed to oxygen at elevated temperatures, the role of oxygen in electrolytic corrosion is that of a depolarizer or a remover of corrosion products from solution. This is indicated by the fact that when corrosion is the result of differential aeration the anode or corroding area is that part of the metal where the supply of oxygen is relatively restricted. The areas where the oxygen is more abundant are the cathodic or protected areas. It seems, therefore, that oxygen is necessary not for the initiation, but for the continuance of corrosion. When some other depolarizer is supplied rapid corrosion may continue, although the supply of oxygen is very limited.

The magnitude of the potential difference resulting from differential aeration in soil was studied by Shepard [24, 1934], who placed two columns of the same soil side by side on a sheet of bright steel and allowed one column to dry out, thereby permitting an increasing supply of oxygen to reach the surface of the metal beneath this column, while the other column was kept moist. A series of measurements of the potential difference between the two columns showed increasing values up to approximately 0·9 volt. This is considerably greater than the potential differences caused by impurities at the surface of iron or between iron and mill scale. Conditions at the surface of a pipe, especially soon after the trench has been back-filled or in locations where the soil shrinks and cracks on drying, approximate the conditions set up by Shepard and afford a potential difference sufficient, if maintained, to account for serious corrosion. The seriousness of corrosion depends on the amount and concentration of the current which flows from the anodic area, i.e. on the magnitude of the electromotive force, the size of the anode, and the resistance of the electric circuit. The last factor is affected by the areas of the anode and cathode, the conductivity of the soil, and the extent of the anodic and cathodic polarization. Not only the magnitude of the differences in aeration which originates the corrosion, but also those factors which tend to suppress corrosion depend on soil characteristics.

Under some soil conditions, especially those in which the soil is neutral or alkaline, secondary reactions may cause a deposit of corrosion products over and adjacent to the corroded area. Depending on the character of the deposit, corrosion may be stimulated by a further reduction of the quantity of oxygen at the anode or a shutting off of the corrosion current because of increased resistance in the circuit. In acid soils there is a tendency for the corrosion product to remain in solution long enough to migrate to such a distance from the buried metal as to be ineffective in preventing continued corrosion. In well-drained, well-aerated neutral soils, such as most sands and silt loams, either the oxygen is so evenly distributed that only small potential differences are produced or the corrosion products are oxidized and precipitated in a partially protective film or layer at or near the surface of the metal.

It has already been pointed out that in an alkaline solution ferrous corrosion products are thrown out of solution. If the solution is sufficiently alkaline, this results in the formation of a film on the surface of the metal which prevents further corrosion. It has been observed, however, that many of the so-called alkali soils of the arid and semi-arid regions are highly corrosive. Some of these corrosive soils are only slightly alkaline. Frequently their conductivity is relatively high because of the soluble salts they contain. In some cases, at least, the corrosion products are not precipitated on the surface of the metal and no protective film results. Whether or not the high conductivity of alkali soils is responsible for their corrosivity, it has been demonstrated that highly corrosive soil areas can be located by systematic measurements of soil resistivity. Indeed, measurements of soil resistivity in one form or another form the basis for most of the more commonly used methods of making soil-corrosivity surveys.

Not all underground corrosion can be attributed to differential aeration, since rapid and continued corrosion sometimes occurs in soils which are continually saturated with water, and hence under conditions where the supply of oxygen is very limited and consequently nearly uniform. Corrosion under one of these conditions has been attributed by Kühr, Von Wolzogen and Van der Vlugt [14, 1934] to the action of sulphate-reducing bacteria. These authors found that the low-lying corrosive soils of Holland contained sulphates from decayed vegetation and bacteria which reduced these sulphates to sulphide. The sulphide not only united with iron or iron ions to form iron sulphide, but acted as a depolarizing agent. While their discussion was confined

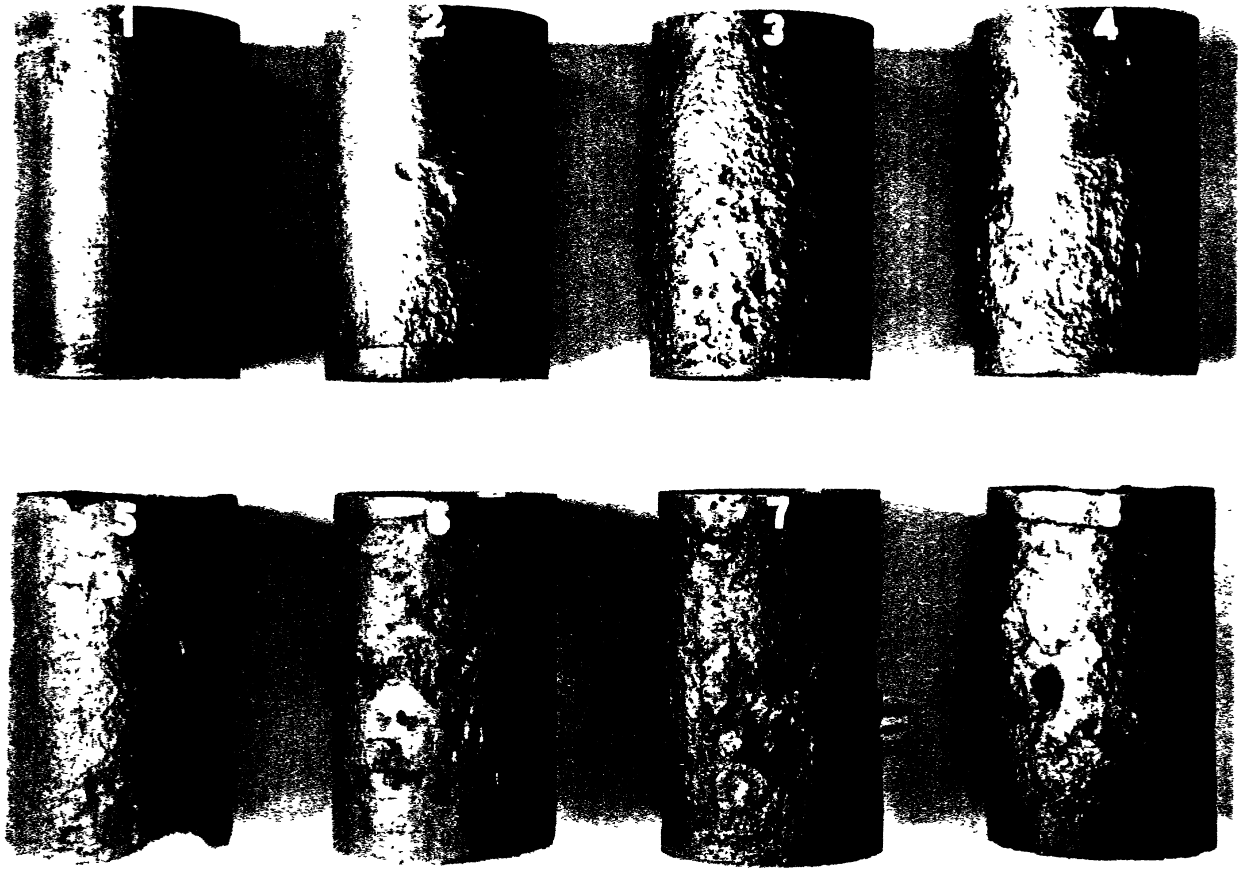

FIG. 2 Open-hearth steel exposed for approximately 12 years to the following soils 1, a continuously wet silt loam, 2, Ontario loam, 3, Susquehanna clay 4, tidal marsh, 5, muck, 6 Allis silt loam, 7, Montezuma clay adobe, 8, Merced silt loam containing alkali Note the differences in the effects of the different soils on the same material

to an explanation of the so-called graphitization of cast iron, there is no reason why it should not be equally applicable to the corrosion of steel under similar soil conditions.

Differences of potential have been observed between points on a pipeline [15, 1930] where the soils are different and between similar electrodes placed in two interconnected soils. It is somewhat difficult to determine whether the observed differences were merely because of differential aeration, differences in moisture, or differences in chemical composition of the soils. It has also been suggested that the differences of potential observed between widely separated points on a pipeline were the result of a current caused by some natural phenomenon such as wind or a magnetic storm. In any event, corrosion has been observed at locations where the density of the current leaving the line was relatively high, and it has been suggested that this phenomenon could be used in the reconditioning of a pipeline.

II. The Characteristics of Underground Corrosion

The corrosion of a homogeneous metal in the atmosphere or in an aqueous solution is nearly uniform unless altered by the non-uniform deposit of corrosion products or foreign materials. The most noticeable characteristic of underground corrosion is its lack of uniformity. Two pipelines of the same material laid within a few feet of each other may corrode at quite different rates. Frequently leaks develop along the bottom of a pipe before the top or sides show any signs of serious corrosion. So generally is the corrosion confined to the bottom of the pipe in certain regions that it is customary to uncover corroding sections of lines and to rotate them on their axes 180° after they have been in the ground several years in order to prolong their usefulness.

In other soils pipes develop a few widely separated pits with intervening sections of nearly perfect pipe. This characteristic non-uniform distribution of corrosion makes accurate determination of the corrosiveness of soils and the relative merits of pipe materials very difficult. Only by averaging a large number of observations taken under similar soil conditions can the rate of corrosion of a material in a soil be determined. Even then the user of this average rate of corrosion must remember that it is an average and that at some point along his line the average may be greatly exceeded. He should also remember that by improper selection of observations the proponent of a material may make that material appear superior to another. Even when no misrepresentation is intended, comparisons of corrosion records of working lines is likely to be misleading because of differences in soil or other conditions, and because the available data are insufficient to yield representative average results. For these reasons properly planned experiments have certain advantages over the assembly of field experiences if rates of corrosion are to be determined.

The conditions of most physical properties can be determined by examinations or inspections of the property. Such an examination is not practicable, however, in the case of pipelines. Consequently, when the condition of a pipeline is required as a basis for valuation or for a reconditioning programme the method of sampling, i.e. of determining the condition of certain small portions of the line, is frequently resorted to.

This may consist of a study of leak or reconditioning records or of uncovering small portions of the line. A fundamental principle involved in the estimation of the quality of any material from a sample is that the sample must be representative of the material, i.e. the units which together make up the sample must be so chosen that each characteristic of the entire mass is represented quantitatively as well as qualitatively. If the material sampled is non-homogeneous, the number of units must be large in order that the varieties may be properly represented. Unless a replacement record covers the replacement at least once of every section of the line it alone cannot correctly represent the condition of the line, since the conditions of the unreplaced portions are not represented. Likewise, leak records tell nothing about those portions of the line on which no leaks have occurred. If excavations are made for the purpose of determining the condition of the line, three methods are available. The most common one is the random selection of points for examination. Too frequently this method degenerates into the selection of what is thought to be the worst or the best sections of the line. To avoid this collection of unrepresentative samples Gill [11, 1932] has advocated the digging of test-holes at equally spaced intervals and has shown that the interval should not be more than 1,000 or 2,000 ft. for the pipelines on which he collected data.

A modification of this method which would give a representative sample is to identify the soils with respect to their corrosiveness and to make a sufficient number of examinations in each soil group to yield representative data on the condition of the line in that soil group. The data must then be considered according to the amount of pipeline in each soil.

In any case, each excavation should expose the same amount of line and the same number of measurements should be made. The U.S. Interstate Commerce Commission in Valuation Order 27 required that where test-pits for inspections of lines were necessary, 4 ft. of pipe should be exposed and cleaned and the deepest pit in each of four 1-ft. sections recorded.

One who is unfamiliar with underground corrosion might assume that the average of such observations would represent the condition of the line. It is evident, however, that the average will not represent the deepest observed pit, and it is highly probable that the deepest pit on the line has not been observed.

Another characteristic of observations of maximum pit depths in connexion with the study of underground corrosion is the relation of the maximum pit depth to the size of the area examined. This is really not so much a characteristic of corrosion as of the selection of any maximum from a group, i.e. the greater the number of individuals in a group the greater the expected variation within the group. In other words, an observer can expect to find a deeper pit on a length of pipe than on a single foot of that pipe. Another phenomenon, again of mathematics rather than of corrosion, is the fact that if an observer makes several observations of the deepest pit on several unit areas and averages them, his result will be smaller than the deepest pit observed. While this fact is obvious it sometimes has been overlooked in the manipulation of soil-corrosion data, and confusion as to the relation between areas and maximum depth of pits may have resulted.

Scott [20, 1933], from a study of pit depths on several sections of working oil- and gas-lines, arrived at the conclusion that the relation between the average maximum pit depth and the area under observation could be expressed approximately by the formula $\log P = a \log A + \log b$,

where P is the average maximum pit depth associated with the area A, and a and b are constants associated with soil characteristics. The formula is a mathematical way of saying that the greater the area examined the deeper will be the deepest observed pit. For some soil conditions this statement seems to hold throughout the range of pipe areas on which pit-depth data are available. In other soils it appears that the value of the deepest pit at least closely approaches a limiting value for relatively small areas, i.e. the pit-depth area equation is hyperbolic. The pit-depth area relation has not been sufficiently well established to justify the estimation of the deepest pit on an area much greater than that for which data have been actually obtained.

Fig. 3 shows the pit depth-area relation for one soil as indicated by Scott's formula. The constants used were determined from pipeline data. The importance of the relation just discussed will appear in the coming discussion of the estimation of pipeline conditions.

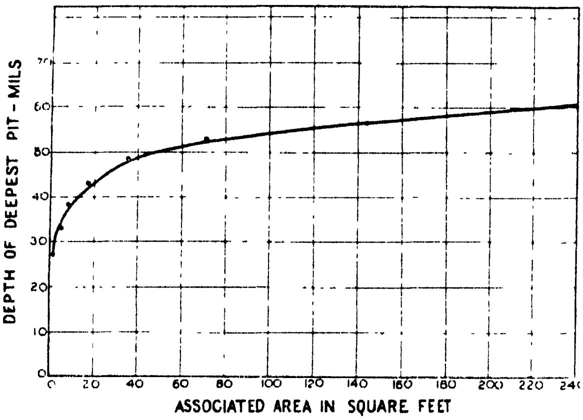

FIG. 3. Relation of average maximum pit depth to area of pipe from which the average was computed.

The influence of the duration of the exposure on the rate of corrosion of iron in soil is shown by the Bureau of Standards soil-corrosion data. When the depths of the deepest pits removed from a soil were plotted against the ages of the specimens, it was found that in many soils the average rates of corrosion were less for the older specimens, as is shown in Fig. 4. Data on pit depths of different ages on working lines show the same tendency to a more marked extent.

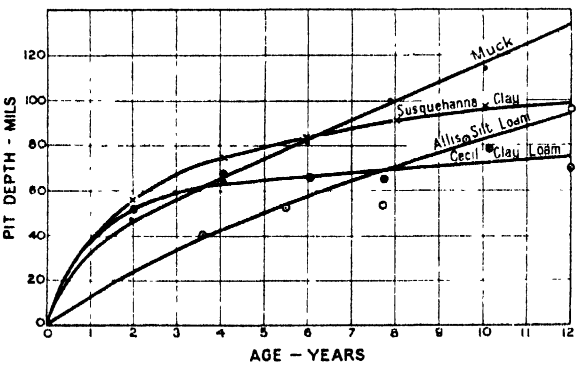

FIG. 4. Relation of depth of pit to age of specimens. Note that the rates of corrosion change with time and the relative corrosiveness of soils does not remain constant.

It appears, therefore, that for certain soils, at least during the first few years of exposure, the depth of the deepest pit is not directly proportional to the time of exposure. However, field data purporting to show the relation of pit depth to time are subject to two criticisms. First, the older pipes may not lie in the same soils in which the newer pipes are buried, and hence the true relation between pit depths and duration of exposure may be obscured by the effects of differences in soil corrosivity. Second, the observations on the very old pipes are liable to be confined to pipes buried in the less corrosive soils only since those exposed to the more corrosive soils may have been removed because of failures. This is illustrated by the experience of a large gas company which on plotting a curve intended to show the relation of pit depths to ages of the pipes in their system, found that the curve reached a maximum at about 8 years and then turned downwards, indicating shallower pit depths for greater periods of exposure.

Scott [21], from a study of pipeline corrosion data, reached the conclusion that the relation between pit depths and time of exposure could be expressed by the hyperbolic equation $P = \frac{UT}{B+T}$, where P = the pit depth at any time T; U the ultimate pit depth, i.e. a constant characteristic of the soil; and B a constant which he found to be approximately 5 for all soils investigated.

Ewing [7], applying Scott's formula to other pipeline data, found higher values for the constant B, and concluded that the relation between pit depth and time could be represented as well, and for his purposes more conveniently, by the exponential equation $P = kT^n$, in which k and n are constants characteristic of the soil. Since both Scott's and Ewing's empirical equations can give curves of approximately the same shape and were selected because they expressed approximately observed relations, the choice between them is controlled by the relative ease with which they can be used.

Since the equation representing the relation between pit depth and time contains two constants, it is necessary to obtain data on pit depths for two periods of exposure in order to evaluate these constants before the equation can be used to determine the pit depths at some time in the future.

Not only do the rates of corrosion differ widely for different soils, but the relative corrosiveness of two soils differs for different periods of activity and with respect to different materials. The first part of this statement is illustrated in Fig. 4, in which it will be noticed that several of the curves showing the relation between pit depth and age cross each other.

The crossing of the curves is due to the fact that the shape of the curve is determined by the characteristics of the soil. Under some soil conditions corrosion products retard corrosion, while in others there appears to be little polarization or deposition of protective corrosion products. Under the latter condition the depth of the deepest pit is approximately proportional to the period of exposure.

III. Determination of Corrosivity of Soils

If, as has been shown, the rate of deterioration of a pipeline depends upon the soil to which it is exposed, it is important to know what soil characteristics cause or are favourable to corrosion and how corrosive soils can be identified. Starting with the assumption that the amount of metal removed is proportional to the current which flows, and with the knowledge that this current is controlled by

the electromotive force, the resistance of the soil through which the current flows and the extent to which the flow of current is retarded by polarization and the accumulation of corrosion products, the corrosivity of soils might be estimated from a knowledge of the relation of soil characteristics to the above-named phenomena. In the absence of sufficient information as to these relations the corrosivity of soils may be determined by associating specific soil types, classes, or groups with observed results of exposures of metal to these soils. The first method permits the estimation of the corrosivity of new soils as soon as certain of their properties are known, while the second requires extensive observations of the effects of each soil or soil group. As there are several thousand soil types, the association of corrosion with them seems a very large undertaking.

The first attempts to estimate soil corrosivity were based on chemical analyses, and the results were unsatisfactory because of the large number of elements and combinations of elements in soils and the absence of information as to the corrosiveness of most of those elements.

Recent investigations at the Bureau of Standards suggest that better results will be obtained when the action of the soil ingredients in the formation of corrosion products is better understood, since it appears that it is not their tendency to corrode iron, but their property of hindering corrosion which is important.

Somewhat later the resistivity of the soil was taken to be the controlling characteristic. Several equally effective methods for estimating the corrosivity of soil were developed which depended very largely on this characteristic, although in some cases the authors of the methods did not fully recognize that the resistivity of the soil under test controlled their results. While resistivity tests proved satisfactory in some localities because the resistivity of the soils was closely associated with other soil characteristics such as moisture and salt content, it soon became apparent that since two soils of the same resistivity did not always have the same corrosivity some other characteristics must also be taken into account. Among these characteristics are polarization and the formation of corrosion products which interfere with the flow of current. Unfortunately, from a scientific standpoint, the development of methods of identifying corrosive soils has been somewhat retarded by the desires of some investigators to commercialize their theories, since this desire interfered with a full explanation of methods used and resulted in the patenting of testing apparatus.

Among the soil-testing methods having resistivity for the controlling factor are the Corfield test [4, 1930], an electrolytic laboratory test involving a superimposed current and some polarization, the Putnam test [17], a short-time laboratory test which also took some account of polarization as well as of soil resistivity, and the Shepard [23, 1931] rod test, a simple field measurement of soil resistivity with apparatus designed to avoid polarization effects.

All these methods have proved successful in the identification of corrosive soils whose corrosivity depended largely on the presence of soluble salts. Comparisons of the results of these methods indicate that they are about equally successful and not greatly different in cost. A somewhat more elaborate method has been suggested by Schlumberger and Leonardon [19, 1932].

Soil resistivity has not proved a satisfactory criterion for the corrosivity of soils in the eastern part of the United States where the concentration of soluble salts is usually low. For these soils, with the exception of sands, Denison and Hobbs [6, 1934] found the total acidity of the soil to be an indication of its corrosivity towards specimens buried for a limited period of time.

At the request of the American Gas Association, Ewing [8,1934] made a study of soil resistivity and acidity as indications of corrosivity, and came to the conclusion that for the pipeline studied neither characteristic alone was satisfactory, but that the corrosivity of soils as indicated by the replacement record of the lines studied could be represented by the formula

$$P = \frac{(A-5)\,8{,}000}{R},$$

where $P =$ percentage of a line reconditioned within a period of 30 years, A the acidity of the soil in milliequivalents of hydrogen per 100 g. of soil, and R the resistivity of the soil type in ohm-cm. at 60° F.

In another study of a pipeline replacement record Denison [5, 1931] showed that the replacements were characteristic of the soil types which the lines traversed. Subsequent studies of other pipelines confirm the idea that although within any soil type the range of pit depths may be large, when observations are taken in a systematic way the average maximum pit associated with a soil type is characteristic of the soil type. A knowledge of the corrosivities of the soil types traversed by a pipeline is a sufficient basis for predicting the life of the pipeline. It seems probable that further investigation will show that much broader and larger soil units can be associated with characteristic rates of corrosion.

Frequently attempts have been made to determine whether the corrosion observed at a certain point was the result of soil action by some analysis or test of a small sample of the soil found adjacent to the corroded area. The difficulties in the way of a correct determination should be evident from what has been said. It should be possible to determine whether a sample of soil has inherently corrosive characteristics such as high acidity, high salt content, or depolarizing agents, but at least part of the corrosiveness of a soil is the result of a difference of conditions at two points along the buried pipe, i.e. corrosion may result not from one soil, but because of the interaction of two soils or soil conditions. The laboratory tests usually only disclose whether or not the soil is favourable to a continued flow of current if conditions provide a difference of potential.

Since in many parts of any country a pipeline would lie mostly in soils which are only mildly corrosive, and since a study of soil conditions in sufficient detail to permit the setting of the boundaries between corrosive and non-corrosive areas involves a considerable expense which is justified only in case the work results in a reduction in the cost of protective measures sufficient to pay for the survey, the builder of a pipeline frequently finds it difficult to decide between laying his line bare, protecting the entire line, or attempting to identify the corrosive soils. While the cost of making a corrosivity survey can be estimated with a fair degree of accuracy, the saving to be expected can only be estimated after the work is done. Under some conditions, at least, one fairly familiar with the relation of soils and topography to corrosion can make at low cost a reconnaissance survey which will indicate whether a more detailed survey would probably be justified. Specific problems in the economics of soil-corrosivity surveys have been discussed by Ewing [9, 1935], who has also outlined his ideas of the proper way to make and use such a survey.

IV. Determination of the Physical Condition of a Pipeline

Knowledge of underground corrosion phenomena may be useful in reducing corrosion losses or in the estimation of the present condition of a pipeline in terms of its original condition. In the latter case the information desired is not the depth of the pits or what should be done to retard the progress of corrosion, but what fractional part of the useful life of the line has been expended. This question arises whenever a line is to be valued for sale, taxation, or rate-making purposes. It is generally recognized that the value of a line for any of these purposes may not depend on its physical condition; nevertheless, its physical condition frequently requires consideration.

The relations between the factors influencing corrosion data have been expressed mathematically by Ewing [8, 1934] and Scott [20, 21, 1933]. Combinations of these formulae have been used to express the physical condition of the line. These formulae are based on the idea that soil characteristics determine the corrosivity of the soil and require the use of several constants obtained either from a previous knowledge of the soils involved or deduced from a statistical study of pit-depth observations. Space will not permit a detailed presentation of the development of the formulae and the methods of determining the necessary soil constants.

Although the formulae appear rather formidable, their manipulation and the determination of the values of the constants are not difficult if sufficient pit-depth measurements are available. The reliability of the results obtained by the solution of the equations will obviously depend in part, at least, on the precision with which the constants have been determined. The formulae are all empirical, and the authors do not claim that they exactly represent the relations they purport to express. They are, however, the results of studies of a very considerable number of pipelines, and, at least, approximately show observed conditions.

Ewing, by a combination of Scott's formulae [20, 21, 1933], obtained a relation between leaks or pit-depth area and time as expressed by the formula

$$A^a = \frac{tB}{c}\frac{1}{T} + \frac{t}{c},$$

in which A is the area associated with a leak or pit, T is the time for the development of a pit of depth t, which in the case of a leak is the thickness of the pipe wall, and a, B, and c are constants. Since the above equation has the form of an equation for a straight line, Ewing determines the values of his constants by arbitrarily selecting values for a until he has found one which gives a straight line when values of A^a are plotted against values of $1/T$. The slope of the line is tB/c while the intercept is t/c.

Ewing also developed another formula on the assumption that the relation between pit depth and time was logarithmic. On this basis the formula is

$$\log A = -\frac{n}{a}\log T + \log\left(\frac{t}{k}\right)^{1/a},$$

and determined his constants by plotting observed values of $\log A$ and $\log T$.

Of his equations Ewing says: '. . . if the constants in the equations are determined for a pipe line, and if the equations are true one then has all the information he needs and can ever obtain about the corrosion of a pipe line. This information can be obtained from either pit measurements or leak records or both.' Since the use of Ewing's formulae involve the plotting of the observed relation between time and area per leak or pit, they are usable only when the available data include observations after more than one period of exposure. They are especially valuable in the study of leak records.

V. The Prolongation of the Usefulness of Pipelines

Whether or not in the design of a pipeline account should be taken of the corrosiveness of the soils to be encountered is largely an economic problem. While certain sections of many pipelines corrode very rapidly, these sections usually comprise but a small percentage of the pipeline mileage.

Undoubtedly there are localities such as marshy ground, alkali spots, and areas contaminated by the drainage from mines and oil-wells where something other than, or in addition to, ordinary pipe should be used. On the other hand, there are many areas in which the soils are not sufficiently corrosive to justify taking precautions against corrosion, unless the cost of repairs or the damage resulting from leaks is likely to prove excessive. Under some circumstances it may be good practice to design a line with the expectation that a few leaks will develop long before the line becomes obsolete.

The life of a pipeline can be extended by the use of corrosion-resistant materials, protective coatings, or some method of counteracting the corrosiveness of the soils. Although use of a corrosion-resistant material seems to many the simplest of these methods, little progress has been made in the development of an inexpensive material which is generally satisfactory. It has already been pointed out that the experiments of the National Bureau of Standards indicate that under similar soil conditions cast iron, wrought iron, and steel corrode at nearly the same rates. While there are several instances in which one material has given markedly better service than another under apparently similar conditions, it is very difficult to determine whether or not small differences in soils, drainage, or other conditions were not responsible for the results. Where short sections of lines are compared the relative merits of the materials may be fortuitous.

Certainly pipeline engineers are by no means agreed on the relative merits of the commonly used pipe materials. This lack of agreement is an indication that the superiority of any one of the materials is not well established. There is, however, considerable evidence that additional pipe-wall thickness, whether of cast iron or steel, results in more than a proportional increase in pipe life in most soils.

In 1932 the Bureau of Standards buried approximately 35 varieties of ferrous and non-ferrous pipe materials in 15 corrosive soils. The results of the examinations of the specimens after 2 years' exposure are not conclusive as to the usefulness of these materials even under the test conditions except, perhaps, in the cases in which the specimens failed within the 2-year period. Even when failure has occurred within this period, the result may be fortuitous since only 2 specimens of each material from each soil were examined. Nevertheless, the results are suggestive of what may be expected of the corrosion-resistant materials available at the time the test was undertaken. The following statements are based on this and other Bureau of Standards field tests.

The addition of 0·2% of copper to steel did not improve the performance of the specimens of this alloy in the Bureau of Standards 12-year soil corrosion test in normal soils. Indeed this material seemed to be not quite so good as Bessemer or open-hearth steel. The poor showing of

the specimens in this test may be due in part to the patches of heavy mill scale which adhered tightly to the specimens. In view of the performance of the copper-steel specimens in the A.S.T.M. underwater tests, it was scarcely to be expected that the material would prove superior when exposed to soils, since the conditions for the formation of the thin, tightly adhering rust layer which protected the metal against atmospheric corrosion were not present. However, 2 specimens of an alloy of copper and molybdenum appeared to be superior to ordinary steel when exposed to cinders for 2 years.

The addition of 4 to 6% of chromium to steel appears to have little effect, at least on the initial rates of corrosion of steel in most corrosive soils, although the specimens of this alloy also appeared markedly superior to mild steel when exposed for 2 years to cinders. An alloy of 18% chromium and 8% nickel appeared to be somewhat superior to an alloy containing the same percentage of chromium and no nickel. While both of these materials pitted much less than other types of ferrous materials tested in nearly all soils to which they were exposed, they showed a few relatively deep pits when exposed for 2 years in a tidal marsh. Under a few soil conditions even polished stainless-steel specimens developed one or more deep pits within 2 years.

Cast iron containing approximately 14% silicon has proved very resistant to most soil conditions, but it has developed a few soft spots in one or two soils containing chlorides and organic matter. Cast iron containing 2·6% chromium and 15% nickel was superior in the 2-year test to the ordinary cast iron and steel, but inferior to stainless steel in most corrosive soils.

Copper and high copper alloys corroded less than most of the ferrous alloys, but showed distinct signs of corrosion in cinders and soils containing hydrogen sulphide. Alloys high in zinc were not so satisfactory.

Lead corrodes and develops pits under several soil conditions. This observation is confirmed by the report of Andregg and Achatz [1, 1924], and is important because of its relation to lead coatings.

Under most of the soil conditions to which it was exposed, zinc corroded slowly and without serious pitting. Aluminium and two aluminium alloys were exposed to four corrosive soils. The aluminium was superior to the alloys, but not altogether satisfactory in the soils containing alkali. The test of these specimens was too limited to be conclusive as to the general merits of this type of material.

The most common means of attempting to reduce corrosion losses is by the application of a coating. Such coatings have been offered to pipeline operators for 50 or more years. Because of the inadequacy of the earlier coatings hundreds of varieties of pipe coatings have been placed upon the market.

On the basis of materials used these coatings may be grouped in five classes: metallic coatings, bituminous base coatings, resins and gums, vitreous enamel, and cement mortar or concrete. Each of these classes covers a wide variety of coatings. The protective effect of metallic coatings may be manifested in three possible ways: (1) a less corrodable metallic surface; (2) the formation of an insulating film or layer of corrosion products; and (3) cathodic protection. The first two of these causes of resistance to corrosion are often closely related, and in such cases the character of the protective film depends largely on the character of the soil to which the metal is exposed. Thus the corrosion-resisting properties of stainless steel are attributed to the rapid formation and maintenance of an oxide film. When this metal is placed in soils containing no oxygen, any cause which breaks down the original film locally results in pitting.

Two metals in contact with each other in the presence of an electrolyte set up a galvanic potential difference which tends to corrode one of the metals and protect the other. Thus in the case of a galvanized pipe with the base metal exposed in one or more places, galvanic action tends to corrode the zinc and to protect the steel. Usually in the case of a lead-coated pipe the action is reversed. In either case there is a possibility of accelerated corrosion of one of the metals because of the presence of the other. The ideal metallic coating is therefore one which does not corrode or one which forms a thin protective film. In addition, the coating should resist abrasion and be free from pinholes.

Of the metallic coatings for use underground, zinc applied by the hot-dip process is the most extensively used. The protection afforded by this coating depends on the thickness and uniformity of distribution of the coating and on the soil to which it is exposed. The amount of cathodic protection afforded by the zinc after it has been punctured depends upon the conductivity of the soil. The corrosion products of zinc seem to retard but not to prevent further corrosion. A coating of 1 oz. per sq. ft. of metal surface will prevent rusting for from 5 to 12 or more years in most soils. Most galvanized pipes carry 1½ oz. per sq. ft. or more. Just why some soils are more corrosive than others with respect to zinc has not been determined, but the character of the corrosion product is probably important. This in turn depends on the character of the soil.

Lead-coated specimens tested in the Bureau of Standards test were characterized by severe pitting in a large number of soils, although in nearly all the soils they were not pitted as deeply as the corresponding uncoated steel specimens. The few calorized specimens under test reduced but did not entirely prevent pitting.

Specimens of electro-deposited cadmium coating in the American Petroleum Institute tests of protective coating [21] showed break-downs in most of the soils to which they were exposed at the close of 3 years. The average thickness of the coating was only 0·4 ml.

The most commonly used pipe coatings are of a bituminous nature. The chief advantages of this class of coatings are cheapness and ease of application. In general, the greater the ease of application the less the effectiveness. The earlier bituminous coatings were solutions of bitumens in a volatile solvent which were applied by dipping or with a brush. These coatings were too thin to be effective in corrosive soils. They were followed by hot applications of bitumen. This provided thicker and better coatings, but these were usually too easily injured. The next step was the reinforcement of the coatings, which followed two quite distinct lines. One of these, applied principally to coal-tar pitch coatings, consisted of the addition of finely divided siliceous material to form what was termed an enamel. This addition of an inert material stiffens the coating and reduces the softening and the tendency to flow at high atmospheric temperatures. Nevertheless, manufacturers of this type of material have found difficulty in producing a coating which would not crack when rapidly cooled and which would not yield to the pressure of stones and clods in the back-fill.

Because of the yielding to soil stress, users of bituminous materials have resorted to shields and fabric reinforcements. The shields are applied over the coating and may be thin sheet metal such as aluminium, copper, or enamelled steel,

or organic material such as roofing felt. One maker of a bituminous emulsion as well as one maker of an enamel applies a coating of cement mortar over the bitumen.

The reinforcing materials include burlap or hessian, woven cotton fabric of several weaves and weights, rag felt, and asbestos felt. Although the bitumens are generally considered waterproofing materials, the organic reinforcements rot, especially when the coated pipes are placed in mucky soils. Other things being equal, there is less rapid since this, as well as the character of the material, is a factor in the performance of the coating.

Scott, in discussing a similar figure, calls attention to the fact that no coating has a perfect record. This is highly significant when it is remembered that the record of each material is for from 20 to 30 ft. of coated line only, some of which lay in soil which is not very corrosive or destructive to bituminous coatings. It will be noted that in several instances the pit depth on the coated pipes was deeper than

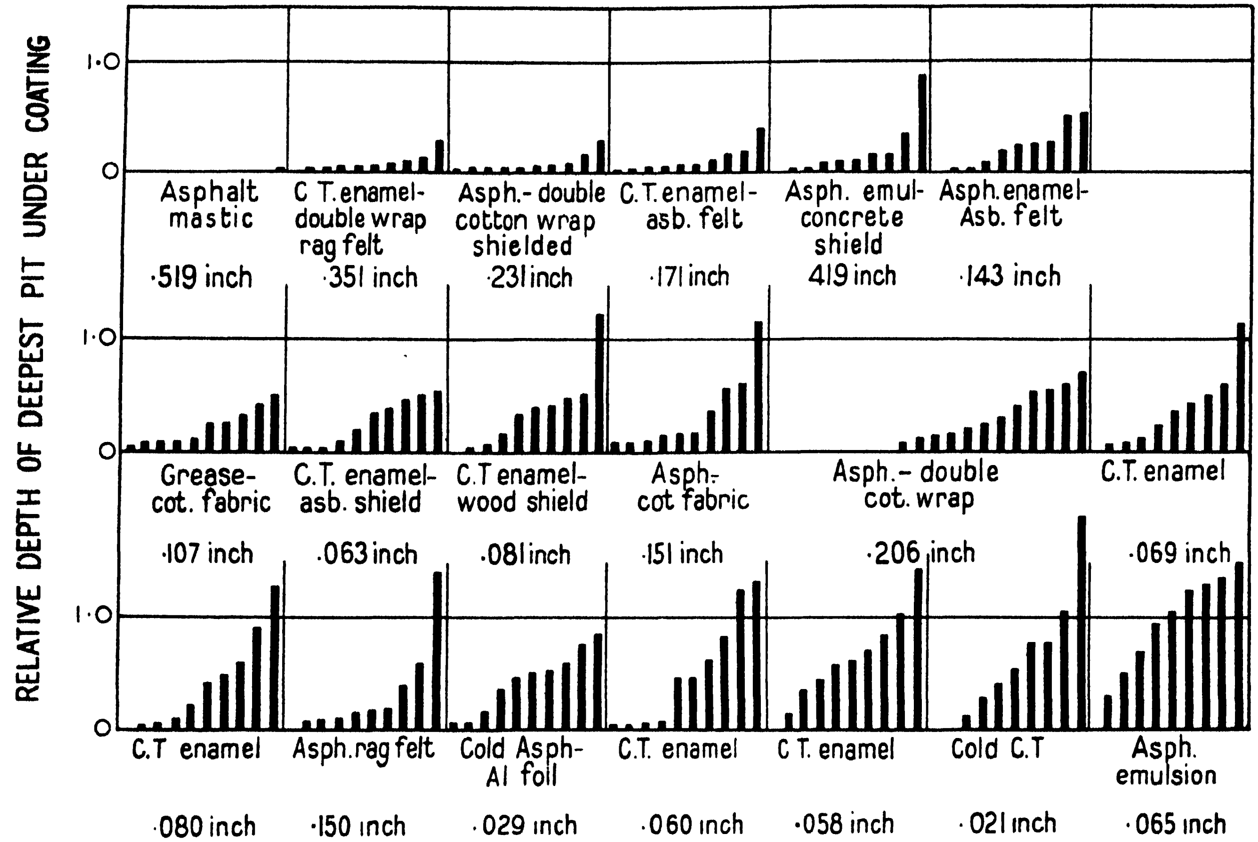

FIG. 5. Effectiveness of protective coatings in the A.P.I. coating test after 3 years' exposure on working oil-lines.

rotting when coal-tar pitch is the bitumen used, possibly because of the bactericidal action of some of the constituents of the bitumen.

The varieties of coal-tar pitches and of asphalts cover such wide ranges of characteristics that it cannot be said that one class of materials is superior to the other, although one or the other may be more suitable for specific conditions.

On the average, the coal-tar pitches are more susceptible to shocks and temperature changes, produce more disagreeable fumes when heated, have a greater tendency to flow under moderate pressures, change less in electrical resistance when exposed to moist soils, and adhere more tightly to the pipe than asphalt-base coatings.

Unless the asphalt-base coatings are quite thick, they absorb or transmit a sufficient amount of moisture to cause rotting of organic reinforcements and a rusting of the pipe surface, which after a time is sufficient to destroy the bond between the pipe and the coating.

The relative merits of materials in the A.P.I. coating tests as reported by Scott [21] are shown in Fig. 5. To Scott's figure the author has added the thickness of the coating, those on the bare sections in the same soil. It is probable, however, that under all coatings the pits were less numerous, i.e. that the amount, if not the maximum depth, of corrosion was reduced.

Among the requirements for a non-metallic pipe coating moisture proofness and high electrical resistivity have been thought to be essential and well met by bituminous materials. How nearly these requirements are met is illustrated in Fig. 6, which shows the change in the resistance of a bituminous pipe coating exposed to moist soil. The curve is characteristic of most bituminous coatings. Unreinforced coatings on working lines frequently lose their electrical resistance rapidly because soil pressure causes localized cold flow.

While there can be no doubt that under some conditions bituminous pipe coatings prolong the life of pipes to which they are applied, the coatings are not in the same class with pipe as materials of construction. Usually the builder of a pipeline does not purchase pipe protection or even a pipe coating, but merely one or more materials which the purchaser or a contractor applies to the pipe. Specifications and acceptance tests are frequently very sketchy or entirely

absent. As a result few coatings have built up an historical background of service, and the pipeline engineer has few definite data upon which to base his decision as to the protecting of this line. Both coating makers and users should

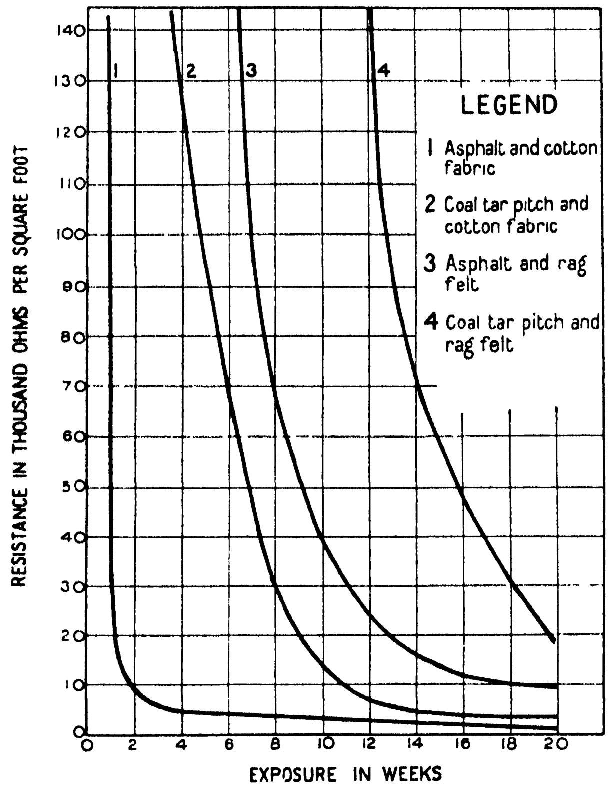

FIG. 6. Change in electrical resistance of bituminous coatings with time of exposure to moist soil.

make an effort to get pipe coatings into the class of engineering materials. A step in this direction would be the preparation of performance specifications for pipe coatings and the testing of the coatings before acceptance. The Clarvoe [3, 1933] coating tester is of great assistance in securing a continuous pipe coating. In 1935 A. L. Smith [25] invented a method for locating weak spots in protective coatings on pipelines without exposing them. In principle the method consists of connecting a high-frequency current between a point on the line and a remote ground. A part of the current which leaks through the weak spots in the coating is picked up by a pair of electrodes placed on the surface of the ground at right angles to the pipeline, amplified, and registered on a sensitive meter or galvanometer. The apparatus is at present in the developmental stage, but preliminary tests seem to indicate that the apparatus will be of considerable use in determining whether a coating is in a satisfactory condition.

To be satisfactory a bituminous coating must be applied to clean dry pipe. This requirement makes field application of bituminous coatings difficult, and failure to meet the requirement is responsible for many coating failures. Because of this, coatings applied at the rolling mill or at a central coating plant have certain advantages. Usually better coating jobs are done at such plants. These coatings are, however, frequently injured before they can be placed in the trench. To obviate this difficulty, machines for coating and wrapping pipe at the trench side have been developed.

The use of a machine by competent operators results in a better and faster job of pipe coating than can usually be secured by hand operations, but there still remains the difficulty of securing absolutely dry pipe and freedom from dust and dirt. Probably the usefulness of coatings would be considerably increased if those who furnish and apply the coating could be made financially responsible for the performance of the coating. There are, however, serious objections to requiring the coating manufacturer to guarantee the performance of his product.

Closely related to the coal-tar pitch and asphalt coatings are the greases. Used without reinforcement they have not been altogether satisfactory. In some cases they are absorbed by the soil, and in others they are penetrated by clods and by moisture. To overcome the effects of soil stress the grease is reinforced or protected by a fabric. As in the case of asphaltic materials the organic fabrics rot in moist soils. The addition of a bactericidal agent reduces the rotting, but does not always prevent it. The performance of one of the grease coatings is shown in Fig. 5. Comparison of a test of this material on short lengths of pipe with a similar test of grease with asbestos felt as the reinforcement indicated that the latter was somewhat superior, although pitting of the pipe was not altogether prevented. The advantages of the grease type of coating are that it can be successfully applied to a pipe which is not absolutely free from moisture and that it can be applied cold or only slightly warmed. One oil company has extensively applied a heavy grease protected by a wrapper of copper foil. No reports on the performance of this coating have been published. There appears to be a possibility of galvanic action between the foil and the steel if the two are brought in metallic contact at any point, since it is not probable that the grease remains free from moisture.

Recently a number of coatings made from gums or resins have been offered to pipeline operators. Most of them are too new to have established their usefulness, and have to be judged largely by experimental data. The first class covers a large variety of materials. In general, laboratory and field tests indicate that coatings applied cold through the use of a volatile solvent are penetrated by moisture within a year or two, and that the coated pipe begins to rust within this period if the soil is corrosive. Nevertheless, since corrosion is most rapid during the first few years after the pipe is laid, such coatings may save their cost. It has not been determined whether a coated pipe corrodes as fast or faster than a bare one after rust begins to form beneath the coating. The limited anodic area would indicate rapid corrosion, but if the cathodic area is also limited, corrosion may be retarded.

Rubber and rubber compounds either as paints or thin sheets have not, in the writer's experience, been entirely successful, although two rather thick rubber compound coatings have withstood corrosive soils for a period of 2 years without signs of failure.

Another new development is vitreous enamel, which has been tried experimentally for several years. Two-year tests in the Bureau of Standards corrosive soils indicate a perfect record for one type of this material. Electrical tests on a short vitreous enamelled section of a gas-line in California indicated numerous fine pinholes in the coating, and later inspections disclosed some pitting of the pipe. Whether or not a vitreous enamel pipe can be laid by the usual type of workmen without injury to the coating, and the limitations as to types of joints that can be used with enamelled pipes, has not been demonstrated, although experiments

indicate that some types of enamelled pipe will withstand considerable shocks and bending. This type of protection applied to the inside of lines carrying corrosive oils might solve a problem which has troubled some oil men.

Cement mortar and concrete have been used to protect pipe against soil action for more than a generation. The chief objection to this type of pipeline protection has been its cost and the difficulty of its installation under some conditions. The question of the stability of cement when exposed to alkali soils has also been raised. The protective effect of cement lies not only in the separation of the soil from the pipe and the maintenance of substantially uniform aeration, but is augmented by alkali in the cement. Knowledge of the relation of alkali soils to cement has also increased, and alkali-resistant cement is now obtainable. One of the large pipeline companies [16] has recently developed a method for applying cement mortar to pipelines by the use of removable metal forms which greatly reduces the cost of the coating as well as the time of application. The thickness of the coating has been reduced to approximately ½ in. Whether this thinner cement-mortar coating will prove as successful as the thicker coatings of concrete can only be determined after longer periods of exposure.

Leaks in concrete-coated pipe have been reported, but in most cases the punctures were the result of poorly made concrete or failure to make the concrete continuous, especially on the underside of the pipe. In applying concrete it is advisable to pour it between one side of the pipe and the form only, and by tamping to force the concrete to flow around the pipe and up the other side, thus avoiding voids beneath the pipe. If a thin coating is to be applied, it will be necessary to use cement mortar instead of concrete.

Lest the reader conclude from the criticisms of protective coatings that they are not worth while, the author wishes to point out the fact that the purpose of a protective coating is not to prevent all leakage, even for a few years, but so to reduce the number of leaks that the annual charges on the line will be a minimum. Undoubtedly, most coatings reduce the number of leaks on the protected line. Whether or not the reduction effected by a given coating justifies the cost of the coating, and whether or not a more economical coating policy might have been adopted, cannot be determined at this time without the use of assumptions which, however reasonable, cannot be supported by adequate statistical data. Nevertheless, the author believes that where soils are known to be corrosive, a high-grade coating should be applied to all but temporary lines.

Because of the injuries and imperfections which have so far been unavoidable in organic base coatings, it has seemed desirable in some cases to supplement the protection which they afford. The means for accomplishing this is known as cathodic protection. The process is based on the fact that at points where it corrodes the pipe is anodic with respect to the soil. If, therefore, a current from a battery or other electrical supply is so imposed on the pipe that the pipe is cathodic with respect to the adjacent soil throughout its length, corrosion will not occur. Among the pioneers in the use of cathodic protection is Kuhn [13], who successfully applied it to some of the lines of the New Orleans Public Service Company.

Ewing [10, 1935] analysed and abstracted most of the published papers on cathodic protection of pipelines available in 1934, and supplemented this information by some work of his own on the theory and design of cathodic protection of coated pipes. The data presented by Kuhn and others indicate that a properly designed system of cathodic protection applied to a pipeline which is fairly well insulated by means of a bituminous coating can afford complete protection to the line at a reasonable cost for power and fixed charges. The resistance of the pipe coating decreases rapidly over a period, depending on the type of coating and on the moisture in the soil, after which there is only a very gradual decrease. While cathodic protection has not been applied to pipelines long enough to demonstrate directly its permanent usefulness, electrical measurements and field tests indicate that the systems in operation are fully protecting the lines to which they are applied. While it was anticipated that the flow of current to the coated pipe would injure the coating, no such result has been observed, possibly because practically all the current passes through ruptures and holidays, and not through the coating material.

Obviously, other things being equal, the poorer the coating the greater the current required to protect the line. It has been generally thought, and some experiments have indicated, that it would be uneconomical to protect a bare pipeline against soil corrosion except when the cost of leaks is very large or the cost of power very small. However, at the 1935 meeting of the Natural Gas Division of the American Gas Association a paper was presented by Rhodes [18] showing that by his patented system bare pipelines could be economically protected. The paper is based on calculations and experiments on a poorly coated line rather than on actual experience with working bare pipelines.

Modification of trench conditions as a method for prolonging the life of a pipe is applicable only where the corroding sections of the line are short. Chemical treatment of the soil such as by surrounding the pipe by lime or a mixture of lime and soil has been proposed [12, 1935] but not used extensively. A number of pipeline operators have replaced the corrosive soil surrounding short sections of lines by sand or clean clay. The clay has been especially helpful when the pipe passed through fills of cinders, because it tends to exclude the soil solutions from the pipe. Sand under favourable circumstances provides more uniform aeration and better drainage. The choice of material should be governed by local conditions.

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MODERN PIPELINE PRACTICE

By W. G. HELTZEL

Stanolind Pipeline Company

THE oil pipelines of America, which serve every practical source of crude-oil supply, constitute an underground system of approximately 116,000 miles of trunk and gathering oil-lines, which extend from the most remote and isolated sources of oil production to the Gulf of Mexico, the Great Lakes, from the Rocky Mountains to the Atlantic Seaboard. In the State of California there is a group of lines leading to and skirting its coast-line.

The gathering systems which, in themselves, are composed of approximately 56,000 miles of pipe varying in sizes from 2 to 12 in. in diameter, stretch out as feeder lines from focal trunk-line points in a far-flung fashion to gather oil in large and small quantities from the remote and scattered oilfields.

Description of American Oil Pipeline Systems

The route of the trunk pipeline is a direct and unswerving course, which each of the various individual trunk-line systems, either as a single or multiple group of lines, takes in its route across country. In these systems there are approximately 60,000 miles of pipe varying in size from 6 to 12 in. in diameter. Such lines may veer from their direct course to skirt the boundaries of towns and cities, but physical barriers do not materially alter their direction. It is a direct route across country, regardless of whether it is over the plain lands of West Texas and New Mexico, or along the prairies of the south-west, across the swamps and bayous of Louisiana to the Gulf Coast, or over the wooded hills and through the fertile valleys of the farm lands in Missouri and Iowa, under the productive lands of Illinois, Indiana, and Ohio, over the mountains of Pennsylvania, and on to the Atlantic Seaboard. All the way from the Susquehanna in Pennsylvania, these trunk lines traverse in their long routes to the oilfields such rivers as the Alleghany, the Monongahela, the Wabash, the Kankakee, the Illinois, the Mississippi, the treacherous Missouri, the Arkansas, the South Canadian, and the well-known Red River. The road beds of the extensive system of railroads and highways are bored, cased, and crossed. Canals, ship channels, and city streets represent a few of the other obstacles in the course of a pipeline to the refineries or seaports. Through the active trunk-line systems there moves a continuous stream of petroleum, under high pressure, 24 hours each day, and almost every day of the year.

The Age of the System

A very small part of this vast system of trunk lines was laid as long as 40 years ago. An appreciable part of it was put in the ground 30 years ago, but the greater portion of it has been built since 1912. The statistical data to figure an accurate weighted average for the number of years the entire system has been in the ground and in service are not at hand, but it is estimated that such an average for the whole system would be less than 17 years.

Previous to 1905, lap-weld thread and coupling pipe, in 20-ft. lengths and diameters of 6 and 8 in., were used almost exclusively in pipeline construction; consequently those parts of the pipeline systems built before that year consist of this class of pipe. It was customary to use 8-in. pipe on the high-pressure end of trunk-line loops with 10- and 12-in. pipe on the low-pressure ends. The use of the 12-in. pipe was limited to the low-pressure end of the line because the strength of 12-in. lap-weld pipe did not permit operating at 600 to 700 lb. per sq. in. safely. This practice continued until about 1928, when the first seamless pipe of high tensile strength came into a limited use. The higher tensile strength could not be obtained in lap-weld pipe, because a high carbon steel could not be welded satisfactorily in the mill operation. However, the use of higher tensile strength seamless pipe made it possible to use 12-in. pipe for high-pressure service also. At first only a limited supply of seamless pipe was available for pipeline construction and, consequently, pipelines built previous to 1931 made use of lap-weld pipe; the Pasotex 8-in. line was an exception. Only seamless or electrically welded pipe is used now for trunk-line construction.

History of Pipelines

The detailed history and progress of the pipeline industry previous to the year 1934 has been collected and summarized [1].

The history of the American pipeline industry reveals that after the pioneering developments in the early years of the industry progress was slow and gradual. For a long period of time few changes in the practices of the industry occurred. The year 1927 marked the beginning of important changes in practices which had become almost traditional with the industry. Science and engineering began to make headway. From that time on major improvements in the pipeline industry have occurred each year. In the first 4 years, from 1927 to 1931, many of our modern practices were developed.

Résumé of Recent Progress

It was during this short time that the low-carbon lap-weld screw and coupling pipe in 20-ft. lengths, which had been used for years, was replaced by higher tensile strength seamless and electrically welded plain-end pipe in 30- to 40-ft. lengths. At the same time pipe with thinner walls came into use. The abandonment of the screw joint was brought about by the successful use of welding in making the field joints.

The advent of this new type of pipe made possible the use of larger diameters for high-pressure work, and consequently more economical design and operation for new trunk lines came about. This advantage appeared in the new trunk lines built during these years. Although oxy-acetylene welding had been used in pipeline construction previous to this time, the introduction of the seamless and electrically welded pipe encouraged and brought about almost the exclusive use of welding for trunk lines. The use of longer joints of pipe, and consequently greater weights in each joint, necessitated the use of tractors and other heavy equipment in the construction of the lines. At the same time, the replacement of the screw and coupling joint presaged the abandonment of the hand tools which

had been used so long that they had almost become symbols of the industry.

This period marked the beginning of the use of electrical welding for pipeline work. Its first application was in the patching, half-soling, and spot-welding of badly corroded pipe in lines which could not be taken out of service. It became a common practice to use electrical welding for putting sleeves over leaking couplings and installing casings over whole lengths of pipe. Electrical welding filled an urgent need in the industry for which oxy-acetylene was not adapted. Although the electrical welding was especially suited for repairing lines which were filled with oil, it had the disadvantage at that time of not being adapted for the welding of butt joints without a back-up or chill ring, and consequently there came into use such joints as the bell and spigot and the double bell with special chill or back-up rings.

As a result of the successful use of welding in construction, forged-steel flanges and short-radius bends were offered to the industry at this time to replace the heavy cast-iron fittings which were not only unreliable, but always subject to leakage. The use of forged-steel flanges, short-radius bends, tees, swages, caps, &c., is established, and consequently the heavy cast-iron fittings are being gradually displaced from service.

During these years investigations revealed that the leakage of gas from wooden-roof storage tanks and the sparking between the sheets or other parts of the tank during electrical storms were the cause of most tank fires. The all-steel welded roof came into use and has almost eliminated tank fires. The use of the floating roof was being rapidly extended to reduce evaporation losses.

The enormous flush production of the Greater Seminole field found many pipeline companies without sufficient capacity to handle the oil from the field, and as an expediency the centrifugal pump and electric motor came into extensive use for high-pressure service in booster or relay pumping stations.

It was during this period that the heat exchanger (making use of the crude oil pumped as a cooling medium) was tried out in closed cooling systems for Diesel engine installations. This use of the heat exchanger was one of the outstanding developments of this period, and it paved the way for the use of Diesel engines where there was either poor water or a lack of supply. It made possible, also, the simplification of Diesel engine installations for both trunk and gathering-line stations. The same development eliminated many problems in the operation of the Diesel engine in oil pipeline service.

The trend in the use of plain-end pipe for welding brought about the development and use of the oxy-acetylene cutting and bevelling machine for trimming and bevelling second-hand screw pipe which was being salvaged for use in new lines.

Important developments, even though fewer and less radical than in the previous 3 years, have occurred in pipeline practices since 1932, either as the result of economic circumstances or the natural extension of the groundwork laid in the previous years.

Valuable information was being obtained from studies of corrosion of the underground pipeline systems. Researches on pressure surges in pump-discharge lines revealed the cause of the failure in these lines. In the field gathering systems of the new oilfields, the steam pump was giving way to the use of portable gas- or gasoline-driven pumping units for pumping the oil from the lease tanks to the first receiving station. The high-speed light-weight Diesel engine geared to a centrifugal pump had come into use in competition with electric motors for gathering-station service. Telephone repeaters were being installed to improve communications on some of the longer telephone systems of pipeline companies. New methods were being developed for draining trunk oil-lines before cutting to replace pipe without the customary large losses of oil and the concomitant damages. Pipeline bridges were being used advantageously for crossing creeks where pipe replacements are frequent or where there is risk of losing the lines in the creeks on account of floods or slides of the creek banks. Orifice meters are being used to advantage at trunk-line and field stations to check pressure drops before going to the expense of covering the lines. The meters aid in eliminating unnecessary shut-down time on account of pressure drops. There has been a large reduction of pipeline warehouse stocks. On account of the reduction in welding costs in the past few years, it has been profitable to salvage large amounts of pipe which were disposed of previously to dealers in second-hand pipe. The undertaking of one major pipeline company to modernize its trunk lines by the replacement of the smaller lap-weld screw and coupling parallel lines with a single 12-in. line has proved economically sound and is noteworthy as a trend [2, 1934]. There is a definite increase in the use of electric welding as against riveting for the smaller steel storage and pipeline working tanks. It is common practice to construct tanks of 20,000 bbl. capacity by electric welding. There have been larger tanks constructed entirely by electric welding. An important development has been the adaption of electric welding for butt joints in pipeline construction. In oxy-acetylene welding the introduction of the multi-flame welding torch has speeded up this type of welding. There has been marked improvement in both the electric and acetylene welding rods as well as the technique of each type of welding.

Important Changes in Field Gathering Systems

For years the steam pump was used to pump the oil from the producers' lease tanks to the first pipeline receiving station; this was especially true in taking care of the large amounts of oil produced in new oilfields.

The light-weight portable multi-cylinder gas or gasoline engine has replaced to a large extent the customary steam power. Usually these units are connected to various sizes of pumps by a V-belt drive. The use of this type of unit has proved itself more economical than the payment of 1 cent a barrel to the producer for steam. An advantage of the multi-cylinder gas-engine-driven unit over the steam pump is that such a unit can be set at a strategic point in the field to gather the oil by gravity from the lease tanks. This arrangement reduces the loss of oil which occurs in the use of many steam pumps and avoids the heavy maintenance expenses on a large number of steam pumps. The gas-engine-driven pumping units are adapted for pumping 400 to 500 bbl. of oil per hour at pressures as much as 300 to 400 lb. This use of the portable internal-combustion engine has made the steam pump almost obsolete for this service.

It is not an uncommon experience now to find that there is no power available for pipeline pumping after the contractor completes the well for the producer; usually the drilling contractor moves the boilers from the lease. Many of the wells are drilled with internal-combustion engines. If the well flows naturally, there is no occasion for the producer to have a continuous supply of power on the lease,

and consequently the pipeline company must supply a self-contained power unit for its use.

The use of the air- or gas-lift is a factor which has also influenced the pipeline companies in the use of a portable internal-combustion unit. An advantage of such a unit is that it is not necessary to depend on the producer for power which is not always available.

In some of the new oilfields, such as western Kansas, there is little or no gas available for use in internal-combustion engines. The crude oil produced from these limestone areas contains hydrogen sulphide gas, and the small high-speed Diesel engine does not perform satisfactorily on this crude oil as fuel. Usually the field gathering stations are isolated, and it is expensive to use gasoline, distillate, or a refined fuel oil. This condition, coupled with the fact that many of the oilfields in limestone areas are scattered, are not as prolific as some of the deep sand-pools, and have a comparatively short life, has made the gathering of oil in such fields very expensive. Semi-automatic electrically powered stations are used by one of the major pipeline companies to meet this condition.

Influence of Proration in New Oilfields

Before the adoption of the proration system, oilfields were developed rapidly and the wells were allowed to flow at full capacity. This condition placed on the pipeline companies the responsibility of handling large volumes of oil at the start, and consequently the pipeline facilities were built to meet unexpected or unforeseen conditions. Proration of the new oilfields made it possible for the pipeline companies to limit their risk in new investments and aids in preventing over-developed and duplicated facilities.

Previous to the proration of new oilfields it was customary to build a large gathering station when the first wells produced oil. These stations were not only complicated as compared with modern-day installations, but also involved large expenditures of money. Such stations involved the use of heavy and cumbersome machinery; its installation was slow and expensive. The investment was too large for the short life of the flush oilfield; however, there has been a marked simplification in field pumping installations even since 1933. The use of the multi-cylinder gas engine or light-weight portable Diesel engine has minimized the risk of making large investments in field gathering stations before the oil production in the field warrants it. This type of equipment has not only aided in simplifying the pumping stations, but has also made it possible to take care of the initial oil production from a newly developed field at a minimum investment. The same type of equipment is being used in the field gathering systems instead of steam pumps. The heat exchanger for cooling the water of the internal-combustion engines has been adapted for gathering-station installations as well as for large trunk-line engines. The present trend is towards the use of the simplest and cheapest installation possible for gathering stations. One major company has made a recent installation in the new Fitts oilfield, Oklahoma, which has neither tanks, suction lines, suction pumps, manifolds, nor even buildings to house the pumping units. The piston-type pumps take the oil directly out of the gravity line from the producer's tanks and relay it directly through the discharge line to a trunk-line station 42 miles away (Fig. 1).

Future Gathering Systems

In entering a new oilfield the pipeline company will probably lay a limited amount of gathering line between the producing lease or leases and the portable gas or gasoline pumping unit which will take the oil directly from the lease tanks and pump it directly to the nearest established receiving station. If the field grows and promises good production, other portable units will be added to run the oil by gravity according to the topography until the amount of production warrants the building of a central receiving station in the field to operate at high pressures in relaying the oil to the trunk line or other intermediate stations. In case of large production on individual leases, such a portable pumping unit as described will be assigned to the individual lease, which is a customary practice to-day in flush fields.

With the development of the portable-type pumping unit, pipeline engineers are giving more careful consideration to the laying out of gathering systems. It is the opinion of some pipeline men that it is more economical to make use of the portable pumping units in gravity zones and lay discharge lines at first, rather than laying a long gravity line between the field and the central receiving station.

The new field gathering-station installations will be simple as compared with the stations built 10 years ago. Although there are plenty of second-hand engines and pumps available for such installations, it will not be economical to make use of such heavy and cumbersome equipment. The accompanying table shows that the older slow-speed engines weigh from 5 to 9 times as much per brake horse-power as the modern high-speed engines:

Comparative Weights of Recent High-speed Engines and the Older Types of Low-speed Engines used in Pipeline Service

Engine make	B.H.P.	R.P.M.	Total wt. (lb.)	Wt. per B.H.P. (lb.)
High-speed engines				
A	300	750	12,000	40
B	105	900	7,250	69
C	50	900	2,675	53
Low-speed engines				
D	300	200	108,000	360
E	140	164	76,000	543
F	60	225	25,000	417

Electric motors have proved reliable for gathering pipeline stations, but the constant-speed motor lacks the necessary flexibility for pipeline operations. This disadvantage is not such a serious handicap as to offset other intangible advantages of electric-motor operation. Usually the deciding factor against the electric motor is the lower operating cost of the internal-combustion engine.

The most promising unit for fields in which a satisfactory crude oil for fuel is available is the high-speed solid-injection Diesel engine or multi-cylinder gas engine connected through a gear increaser to a multi-stage high-pressure centrifugal pump. A closed water-cooling system with a heat exchanger will be used in such an installation.

It is becoming a common practice among pipeline companies to use floating-roof tanks at the central receiving station in new fields to prevent the heavy losses of gasoline and other usable products through evaporation at the first station.

Pipe of thinner walls will be used eventually in field

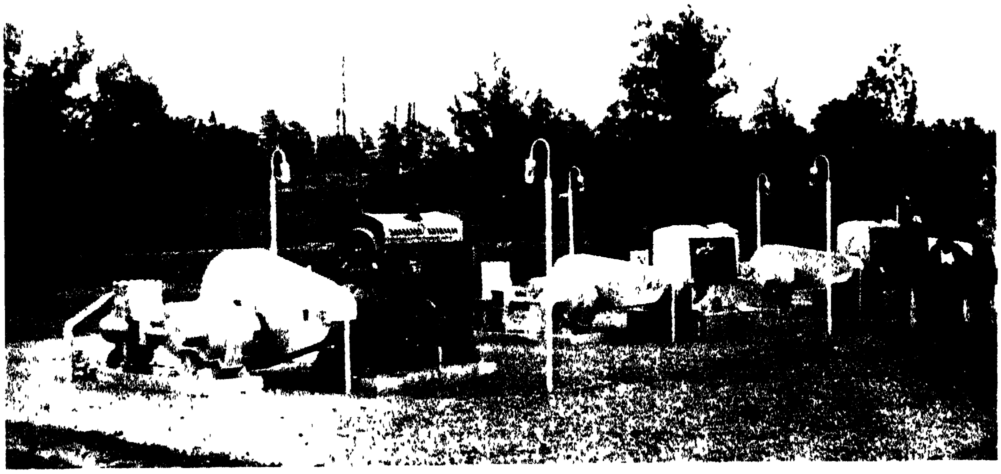


FIG. 1. A modern and low first-cost gathering station

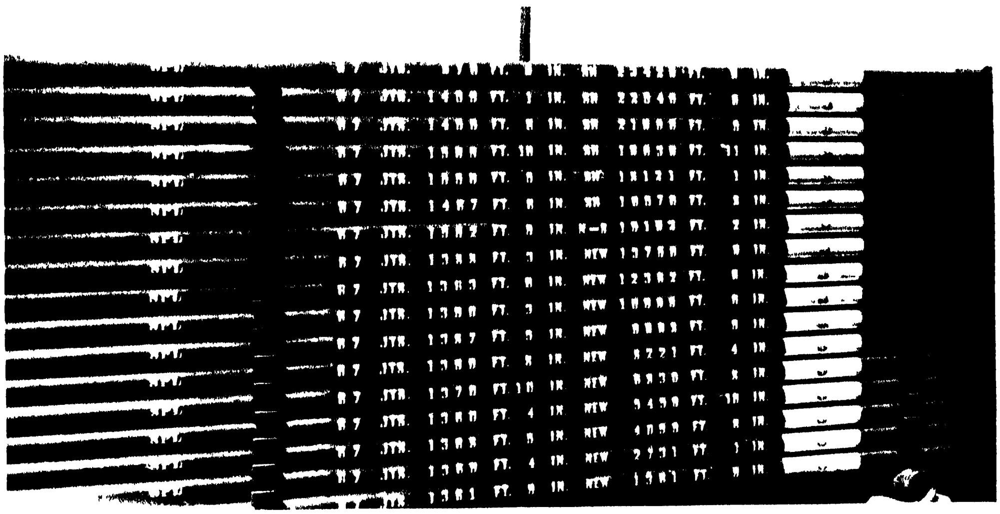


FIG. 2. Good method for racking and marking pipe

FIG. 4. A caravan of modern pipeline equipment along the right-of-way

gathering lines. Were it not for the fact that there is a large amount of second-hand standard-weight pipe which is being made available each year from the duplicated facilities of the pipeline companies, a light-weight pipe would be used now for the gathering lines. Although the future gathering system within a given field will probably be built of such pipe, considerable time will be required to consume the large amount of pipe which can be spared from duplicated systems in the older fields. It is more economical to use, for the present, the second-hand pipe which is available.

Because of the many new developments in the field gathering systems, obsolete steam pumps, heavy oil engines, reciprocating pumps, tanks, and auxiliary machinery which cannot be used economically have accumulated in the warehouses and yards of pipeline companies.

The Efficient and Economical Operation of Oil Pipelines

Notwithstanding the fact that there has been only a small decrease in the consumption of its products during the past 3 years, the oil industry has been under an economic distress as the result of heavy taxes, an over-supply of oil, unfair competition in marketing, and increased labour and material costs. These conditions have brought about economic pressure on transportation rates, resulting in reductions of tariffs. The effect of the reduction in pipeline tariffs will be felt more poignantly with the decline of the flush oilfields and as it becomes necessary to extend or use the existing trunk-line laterals and gathering systems in more remote and scattered areas. Greater efficiency in operation, reduced maintenance costs, and the partial elimination of duplicated facilities in the declining oilfields will be required to meet this trend. There is not only an unwarranted, but also uneconomical duplication of pipeline facilities in the declining fields of the Mid-Continent oilfields of the United States. It has been rather difficult for the various companies to find a satisfactory solution to the problem, and it appears that it will be solved largely by economic forces in course of time. Gradually large quantities of second-hand pipe and other pipeline equipment will be salvaged from such fields for use elsewhere.

It seems illogical to predicate the cost of gathering and transporting oil in the future on the basis of the industry's experience in gathering oil from prolific flush pools which have been explored and developed in areas reasonably near the various trunk-line systems. It should be borne in mind, also, that heavier maintenance costs must be met by the pipeline companies, since their systems are becoming older.

Organization and Discipline in Warehouse Yards

A few years ago it was a common practice of pipeline companies to allow a large amount of unclassified pipe to accumulate in unsightly piles in the warehouse yards. Some of the pipe was crooked; some of it had damaged threads; but much of it remained unclassified because it was covered with a heavy coat of rust and soil. Confusion and disorder was the logical result. An accurate movement of pipe through warehouse stock could not be maintained, and miles of usable pipe was left idle in these heaps of unclassified pipe. The reason for this condition was due partly to a lack of organization and discipline in the warehouse yards, but the principal reason was that the field men did not have a convenient means for cleaning, straightening, and repairing the pipe. There was no code to guide the field men in classifying second-hand pipe. The pipe-straightening and cleaning machines and the use of welding have made it possible to keep pipe yards in an orderly condition, with the result that a large amount of pipe which was kept in idle stock for years is now made available for active use. Of course, such a plan makes it possible to keep better warehouse records. Even when the proper equipment for keeping the pipe yards in good condition is provided, the lack of proper discipline will prevent the accomplishment of an organized plan for a warehouse yard. There is a large turnover of many miles of second-hand pipe and thousands of second-hand fittings in the warehouses of the gathering systems. Unless a plan is provided and discipline maintained in handling this material, an uncontrollable condition develops. In salvaging fittings a cleaning vat is a necessary piece of equipment of such a warehouse. One major pipeline company which handles hundreds of miles of pipe through its scattered warehouse yards each year has found that the expense of keeping its yards in good condition is much less than a disorderly or unsystematic procedure. It is their custom to straighten, clean, and classify at the end of each period of 2 weeks any pipe which is received in the warehouse yard during this period.

Methods used in salvaging Pipe

The pipe is placed on a receiving rack in the warehouse yard after it has been taken up as an abandoned or idle line in the gathering system. Each piece of pipe and each fitting, however small and regardless of its condition, is marked with a job number so that the authorization under which the installation was originally made can be credited with the retirement of all the material which was reclaimed. After straightening and cleaning, the pipe is classified 'A', 'B', 'C', and 'Junk Pipe'. Some entire sections of pipe will fall in one of those classifications; on the other hand, many joints of pipe are partly good and partly bad. In such cases the joint of pipe is cut so that the good pipe can be reclaimed by welding shorter lengths into longer sections. 'Spot' welding is also used for reclaiming some of the pipe. The 'A' grade pipe is that class which has an outside surface free of pitting. This class of pipe may contain joints made by welding together shorter lengths of good pipe. This grade of pipe includes also joints of pipe which have a few small 'spot' welds. Generally, the 'A' grade pipe is considered good for high-pressure oil-line service. When the surface of the pipe is covered with slight pits, or if an appreciable amount of the wall thickness has been lost by 'scaling', no repair is made on the pipe, which is classified as 'B' grade for use in low-pressure or gravity lines in field gathering systems. Sometimes this pipe may be used in the low-pressure and non-corrosive sections of high-pressure lateral systems between the trunk lines and a gathering system. The 'B' grade pipe is never laid in a trunk line or a line which will have an expected useful life of over 10 to 15 years. Sometimes this 'B' grade pipe is thoroughly cleaned and relaid with a protective coating in secondary lines which have an expected life less than 10 years. The 'C' grade type is too badly pitted or has lost so much weight that it cannot be used in oil-lines. A certain amount of this grade of pipe is kept for temporary water-lines, posts, and miscellaneous construction. The 'Junk Pipe' consists of short lengths and badly corroded sections which have no further use in the business. Such pipe is sold as junk.

All classes of pipe are neatly racked and kept separate.

Each tier of pipe is spaced from the other by pieces of lumber 1 by 4 in. A small block is nailed on the end of each spacer to keep the pipe from rolling. The spacers and the blocks are kept in line as shown in Fig. 2. The piles of pipe are kept plumb and square. Each tier of pipe carries on the front joint a complete inventory of the pipe in each tier. The successive tiers all the way to the top tier carry the accumulative total so that a perpetual inventory is maintained. Each tier carries also such information as the number of joints, the total footage of pipe in the tier, and the class of pipe, also the identification mark of the company, and sometimes a hidden stencil identification mark. Often it is not economical to haul the pipe to a company warehouse yard, and it is racked and stored adjacent to a railroad spur in the district where the pipe has been taken out of the ground. The same method of racking as used in the warehouse yards is followed also for these temporary racks. As a means of discouraging theft of pipe left on these temporary racks, each joint is stencilled with a hidden company symbol and the entire rack of pipe is tied down to the skid with iron bars.

Trunk-line Systems

Little or no change has occurred in the trunk lines built early in the history of the industry to serve the Appalachian oilfields; the same condition has prevailed for the lines which were built from Chicago and St. Louis to the Atlantic Seaboard when the Oklahoma and Kansas oilfields were discovered. Although there has been no appreciable expansion in trunk lines in the Mid-Continent and Gulf Coast areas since 1932, and only a few extensions have been made in the gathering systems on account of the prolific flush Oklahoma and Texas pools, the history of the oil pipeline industry in the Mid-Continent and Gulf Coast areas has been marked by continuous expansion of its trunk- and gathering-line facilities.

For the present it appears that the trunk-line systems are adequate, and one cannot anticipate any large construction programmes for increasing the capacities of the present trunk-line facilities. East and West Texas, as well as the Panhandle, appear to be adequately served with tributaries to the trunk lines. Development of oilfields in western Oklahoma would necessitate the building of some lines in that direction. A reasonable expansion of pipeline facilities in Kansas during the next 2 or 3 years can be expected.

Continuous changes will occur in the gathering systems on account of the decline of old fields and the development of new pools which will require, in addition to the building of new gathering systems, the extension of lateral or tributary lines from the trunk lines to the new fields. Undoubtedly the attention of the pipeline engineers and executives will be shifted from large construction programmes to the planning for more efficient operation and ways of meeting approaching obsolescence and heavier maintenance schedules. It should be remembered that the present average age of the pipeline systems in the Mid-Continent and Gulf Coast areas is less than 15 years. Some of these systems are reaching the age at which a surprising amount of obsolescence develops. Unexpected maintenance costs must be encountered. It is true that some of the older pipeline systems are still operating with their original equipment and lines (this is the case for some of the older eastern lines) with a reasonable amount of maintenance expense. Their maintenance schedules, however, cannot be used in planning for a maintenance programme for the systems which must be kept up to capacity, because most of the older lines referred to above have spare line capacity and machinery. It is logical to believe that important developments will occur in the field of economical operation in future years which will be comparable to the progress made in the past 10 years in improving lines, machinery, equipment, and practices.

Trunk-line Construction

In the construction of trunk lines or additional loops to trunk lines, the trend has been towards the use of 12-in. pipe. All new pipe laid in trunk lines is either seamless or electrically welded pipe in 30- or 40-ft. lengths. In some States the restriction on the weight which is permissible on highways has made it impossible to use 40-ft. pipe without going to the trouble of obtaining special permits for transporting it. Welding is used entirely as an established practice for joining together the sections in the field. The thread and coupling joint is not used for trunk-line service. As a result of the seamless and electrically welded pipe higher tensile steel is used. Years of practical operation have proved the reliability of the welded joint, and the seamless and electrically welded pipe has proved thoroughly satisfactory; however, there is only a small part of these older trunk-line systems of welded or seamless pipe with welded girth joints. Lap-welded pipe in itself is not considered a serious disadvantage in a trunk-line system, but the thread and coupling line requires constant maintenance and is considered obsolete and an economic handicap in the operation of the older trunk-line systems. There are a few individual trunk lines of all-welded construction which, because of their very low maintenance cost, have been an economic and competitive challenge to the older systems with thread and coupling lines.

Some companies have used 12-in. pipe made from higher tensile steel with a wall thickness of $\frac{1}{4}$ in. Such lines have been protected with a bituminous coating and in some cases a wrapper. Other pipeline companies continue to use pipe of standard weights and wall thicknesses and bury the lines bare. One large company uses 45·55-lb. ($\frac{11}{32}$ in.) 12-in. instead of the standard weight 49·56-lb. ($\frac{12}{32}$ in.) pipe. The difference of 4 lb. in the weight of the steel is sufficient to pay for the application of a good asbestos felt and hot asphaltic coating. This composite coating consists of a primer coat, an application of hot asphalt, the bonded asbestos-felt wrapper, and an outside coating of hot asphalt.

Improvement in Construction Methods and Equipment

Pipeline Bridges.

A new feature of the construction of some oil pipelines is the provision of suspension bridges across small creeks and rivers. The bridge provides the protection against the loss of the lines in the creeks and rivers by floods or landslides during high waters. Many of the creeks and rivers in the oilfields carry salt or other corrosive waters which necessitates the replacement of the pipe frequently. To meet these conditions bridges have been built. It is likely that the pipeline bridges will come into more extensive use as it becomes necessary to replace the old lines in creek beds. A typical pipeline bridge is shown in Fig. 3. Some of the features of this bridge are listed below.

1. Clean span—240 ft.
2. Pipelines—one 8-in., one 10-in., and one 12-in.
3. Total load between towers—60,000 lb.

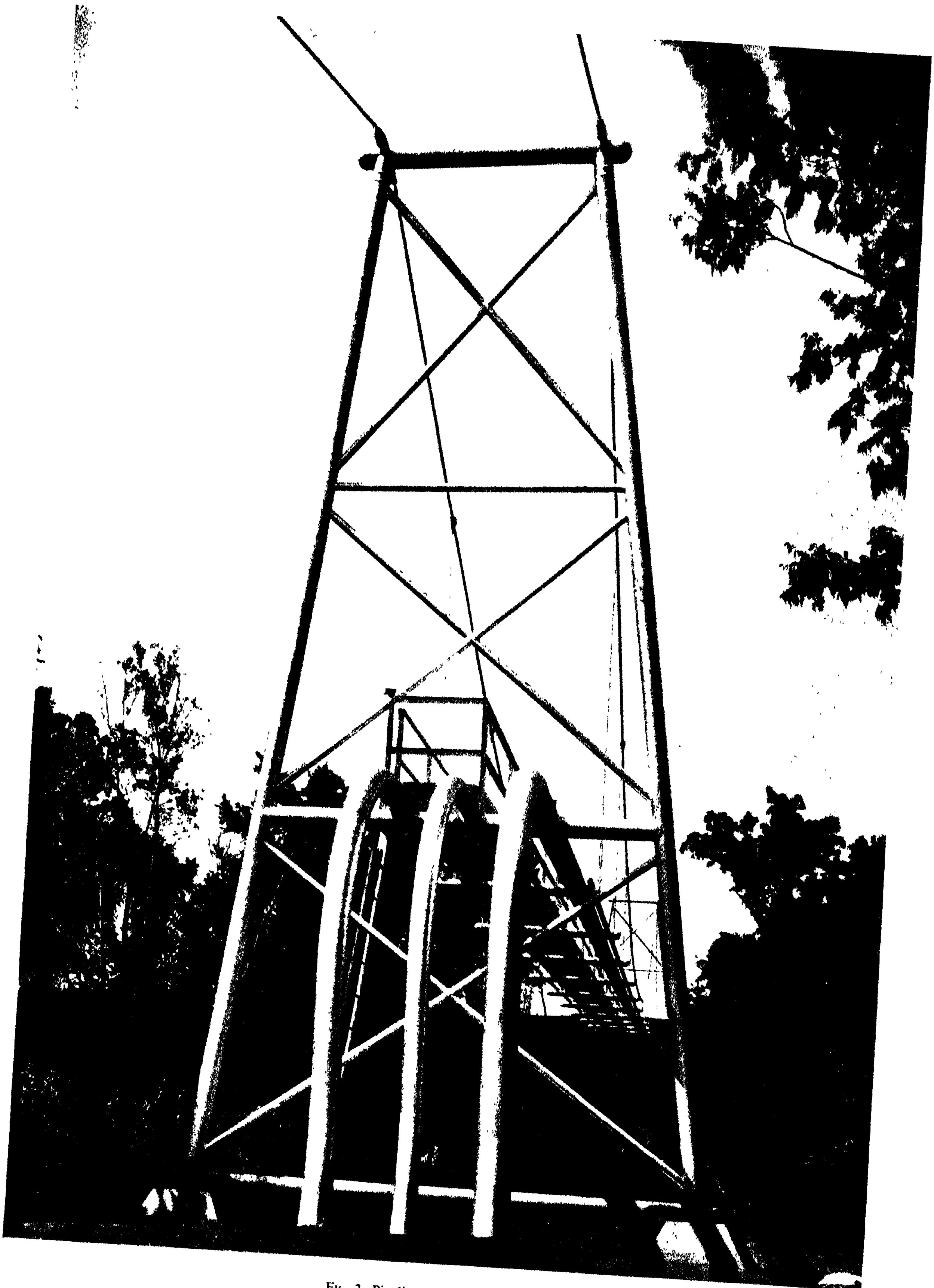


FIG. 3. Pipeline suspension bridge

4. Towers—pivot type—towers move with change in length of back-stay.
5. Cables—two 1⅜-in. single strand, galvanized, plough-steel bridge cables.
6. Expansion and contraction of pipelines—the south bank is 17 ft. higher than the north bank, making it possible for the pipelines to enter the bridge at ditch-level on the south end and leave the bridge via 17-ft. offset bends on the north end. These 17-ft. offsets take care of any expansion or contraction of the pipelines.

Pipeline Construction Equipment

Remarkable improvements have been made in pipeline construction equipment to facilitate the laying of lines. A description of some of the new equipment is noteworthy.

Powerful tractors with booms and winches have replaced the hand tools which were used in the industry for such a long period. The heavy-duty tractors are equipped with booms, which have revolutionized the methods of laying new lines. 'Sags, overbends, and sidebends' are made by cold bending with the tractors. The use of the cradle swung from the tractor boom has been especially valuable in supporting the line for cleaning and coating operations. The cradle rolls along and supports the line as the tractor keeps moving ahead. New welding trailers have replaced the wooden sled provided for the welding equipment. Fast trucks speed men and materials to and from the job, so that it is no longer necessary to maintain camps even in isolated regions. The development of special equipment has made it possible to apply good pipeline coatings in the field. The oxy-acetylene cutting and bevelling machine has been improved, so that good and true bevels can be made on second-hand pipe for welding. The improvements in both acetylene and electric welding have not only speeded up the work, but brought about more reliability in the welds. The experience of pipeline companies in their recent construction is that very few defective welds are found when the line is completed, and this type of construction has proved reliable by years of service.

Newly constructed lines are tested with about 100 lb. of compressed air, which is left on the line from 24 to 48 hours. Certain chemicals are sometimes mixed with the compressed air to develop an odour which can be sensed in the case of small pinhole leaks in the welds when it is not possible to discover the place where the leakage of the air is occurring. Pressure gauges are used on one end of the line to check for air leakage. The use of air for testing has been used in preference over the old method of filling the line with water and testing by hydraulic pressure. Of course, air pressure could not have been used on the thread and coupling line, and the hydraulic pressure of 600 lb. was preferable for testing for defects in lap-welded pipe.

The building of new gravel and concrete highways throughout the country during the past 10 years has resulted in the abandonment of the heavy-duty slow-speed truck and the adoption of faster and lighter weight trucks, which have not only expedited, but also facilitated the maintenance and construction work on pipelines (Figs. 4 and 5).

Improvement in Equipment for Coating Pipelines

A few years ago it was difficult to obtain a satisfactory coating on the lines because of such factors as unsatisfactory cleaning methods, slowness of work, poor application of coating, moisture on the pipe, and poor workmanship. All these objections, except the trouble encountered with the moisture on the pipe, have been met.

The perplexing problem of cleaning the pipe has been solved by the use of a travelling pipe-cleaning machine, which is equipped with a double set of rotating cutter wheels and brushes. The machine is adapted for two cleaning speeds and will clean 6,000 to 8,000 ft. of new pipe in 8 to 10 hours. The cleaning machine travels along the line at the back of a heavy-duty tractor which is equipped with a boom and cradle that permits the tractor and cleaning machine to move forward without a delay in stopping to lower the line on the skids and to move forward to pick it up in advance. This new type of cleaning machine is adapted, also, for going over most of the bends, which eliminates the time required formerly in removing and putting the old-style machine back on the line on account of bends. The development of such equipment as the pipe-cleaning machine and pipe-straightening machine by the W-K-M Company of Houston is an important contribution to the industry (Fig. 6).

The application of hot coatings such as asphalts and coal tars has always been done by a rather crude hand method. The hand method is slow, it ruins the workmen's clothing, results in burns and injuries to the workmen, and causes a large loss of asphalt. The hand application contains holidays and gas bubbles. A coating machine developed by J. B. W. Gardiner of New York City has been used on thousands of miles of pipe to prove its reliability and practicability. This machine corrects many of the faults which were found in the use of the hand method of applying the coating (Fig. 7).

One of the most difficult jobs in the application of a bonded coating was the application of the asbestos felt paper, which was usually wrapped on the pipe longitudinally. About 6 years ago the Johns-Manville Company developed a hand-operated wrapping machine for the application of the coating spirally about the pipe. This machine has been tried on thousands of miles of new lines constructed of new and second-hand pipe, and it has been found that a satisfactory bonded job can be obtained through the use of the machine. As much as 8,000 to 10,000 ft. of 10- or 12-in. pipe can be wrapped in a period of 8 hours. This machine is a practical piece of equipment, and has aided materially in the development of proper methods for applying these coatings (Fig. 8).

Developments in Welding

A statement should be made about the use of welding. The development of a fast rod and the multi-flame welding torch has speeded up, reduced the cost in labour and materials, improved the weld, and facilitated the making of an oxy-acetylene weld. At the same time the oxy-acetylene automatic cutting and bevelling torch has been improved to eliminate the wear in the parts and to give better cutting alinement so that true and good bevels can be made by this machine, which is being used extensively for cutting and bevelling second-hand threaded pipe for welding.

Electric welding generators have become a necessary part of the equipment of each maintenance crew on account of the fact that only this type of welding is adapted to the repair of lines filled with oil, and, consequently, the extension of its use to the welding of butt joints was expected. Electric welding is being used in the industry for the fabrication of piping systems, because the temperature developed in welding does not warp or throw out of alinement

the flanges or fittings which are a part of the piping system. The improvements in electric welding, especially the making of a successful butt-joint weld, has made it possible for pipe-line companies to salvage large quantities of pipe which were rejected because it was not economical to cut out and weld together shorter sections of pipe into longer ones.

Important developments in electric welding have been: the adapting of this type of welding for the making of butt-joint and bell-hole welds, the use of coated rods to give ductile welds, increasing the voltage across the arc from 25 to 40 volts, reducing the weight of the welding generating units which has made them more portable, and eliminating the resistance reactor.

In the making of 'firing-line' or roll welds in the construction of new lines three beads are made as shown in the following table. Five beads are used for making bell-hole welds.

	Size of rod	*Amperage*	*Voltage*
Stringer bead . .	$\frac{3}{16}$ in.	150–200	25–40
Second bead	$\frac{5}{16}$,,	200–250	40
Third bead . .	$\frac{3}{8}$,,	250–325	40

The weight of the 300-amp. welding generating unit has been reduced from 3,000 to 2,165 lb., or nearly 28%, and the 200-amp. generating unit has been reduced from 2,200 to 1,670 lb., or about 24%.

Electric welding has made it possible for pipeline companies to keep in service many miles of pipelines by welding couplings, patching, and spot welding, rather than shutting down and draining lines for pipe replacements. At the same time the accumulation of temporary repairs, such as saddles, stuffing-boxes, and leak clamps, can be kept at a minimum.

When electric welding first came into use, some companies made the electric generator a part of the truck equipment with the generator mounted, in many cases, under the seat of the truck and driven by the truck motor with a special power take-off. Although these welding trucks proved very valuable, the power take-off caused considerable trouble, and it has been necessary to replace this power take-off almost once each year at a high cost. Another disadvantage of this combination was that an expensive truck is restricted in its usefulness. As a result of these experiences some companies have taken the generator out of the truck when the power take-off had to be replaced and reassembled the generator with a Ford V-8 motor on a separate trailer, which also carries an acetylene generator. The truck was rebuilt for hauling men and materials.

Trunk-line Station Equipment

The trunk-line stations of the older pipeline companies were equipped with boilers and triple expansion steam engines. Many of these plants are still in service. Trunk-line stations built during later years are equipped with semi-Diesel and full Diesel engines. Some of the first Diesel engines used in the United States were tried out by the pipeline companies; consequently, one will find in some pipeline stations various types of oil engines. It happened that the growth of the pipelines occurred at a time when important changes were also occurring in the design of the Diesel engine. New engine installations in pipeline stations incorporated the new designs in Diesel engines. The first oil-engine installations varied in size from 60 to 300 h.p. Installations are now made in sizes up to 800 h.p. One will find in some pipeline stations horizontal and vertical engines in sizes from 250 to 750 h.p.; 2- and 4-cycle engines; air- and solid-injection types; and engines with speeds varying from 164 to 277 r.p.m. The bore and stroke of the engines will vary from $13\frac{3}{4} \times 17$ in. to 22×34 in.

The pumps in the American trunk pipeline stations may vary from 12,000 to 48,000 bbl. capacity. The smaller pumps are horizontal duplex double-acting units with 5×24-in. plungers. The larger pumps are horizontal triplex double-acting units with $6\frac{1}{2} \times 36$-in. plungers.

The older pipeline stations have water reservoirs and open cooling-water systems. Usually these stations are large and rather complicated. An exception is the electrically operated centrifugal pumping station. The trend is, however, not only towards simplicity in new stations, but also towards the simplification of existing facilities to reduce maintenance and operating costs of the older stations. Not enough important trunk-line station installations have been made in recent years to mark any change in practices as to the use of machinery. Solid-injection engines with higher speeds have been purchased in preference to the air-injection engines for the few new installations which have been made. Appreciably higher speeds and lower weights per brake horse-power are used in the design of these engines.

As a rule an engine for pipeline service uses the same crude oil which is pumped by the unit rather than special fuel oils as recommended by the manufacturer. It appears that considerable research and development work must be done by the manufacturers to adapt the high-pressure solid-injection system to the use of all grades of crude oil as fuel. It should be borne in mind that engines for pipeline service are installed sometimes in remote areas where it would be difficult and expensive to deliver special fuels, and in certain areas only corrosive crude oils are produced. Operating experience indicates that corrosion in the fuel pump and injection nozzles results in leakage and a loss of balance in the fuel charges to the cylinders, which in turn develops serious operating and maintenance problems. The parts of the injection system are subject to very active corrosion when crude oils with a high sulphur or hydrogen sulphide content are used.

The reciprocating pump is still used for large-capacity installations. Because of its lower efficiency and lack of flexibility in operation the centrifugal pump has not been able to replace the reciprocating unit.

For high-pressure pumping service most pipeline engineers are inclined to the use of forged-steel cylinders, because it has been learned by experience that frequent failures occur in the castings in course of time, whereas a failure in the forged-steel cylinders of pipeline pumps is so uncommon that such cylinders are regarded as free from bursting failures.

The development of hard-surfacing materials and heat-treating processes has brought back into use the wing-guided valve, which gave way to the use of the ball valve years ago. Some of the advantages of this type of valve are less weight, quieter operation, and low maintenance cost.

New pumps will probably have fewer valves than the older types, because operating men have found that operating troubles are more frequent and the maintenance expense is higher for pumps with the greater number of valves. Any appreciable reduction in the number of valves will result in operating economies.

The development of the light-weight high-speed Diesel

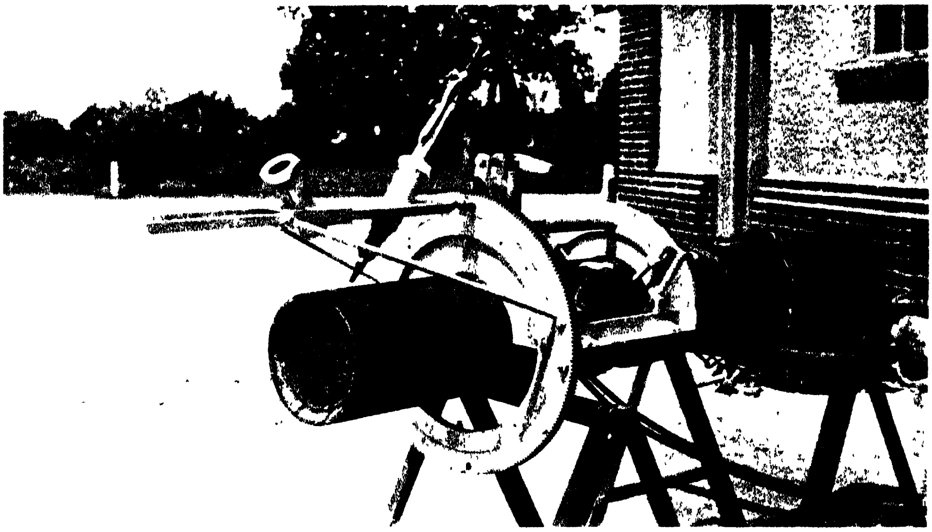


Fig. 5. Oxy-acetylene pipe levelling machine

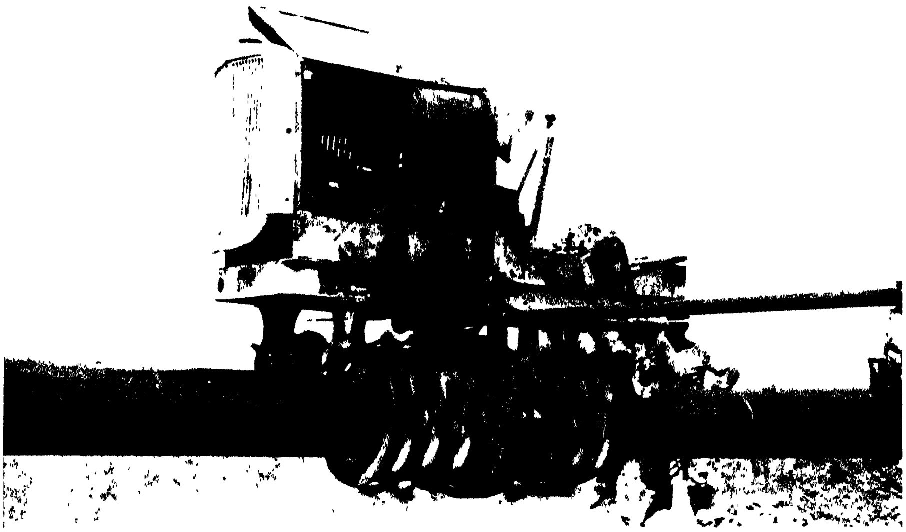


Fig. 6. The travelling pipe cleaning machine

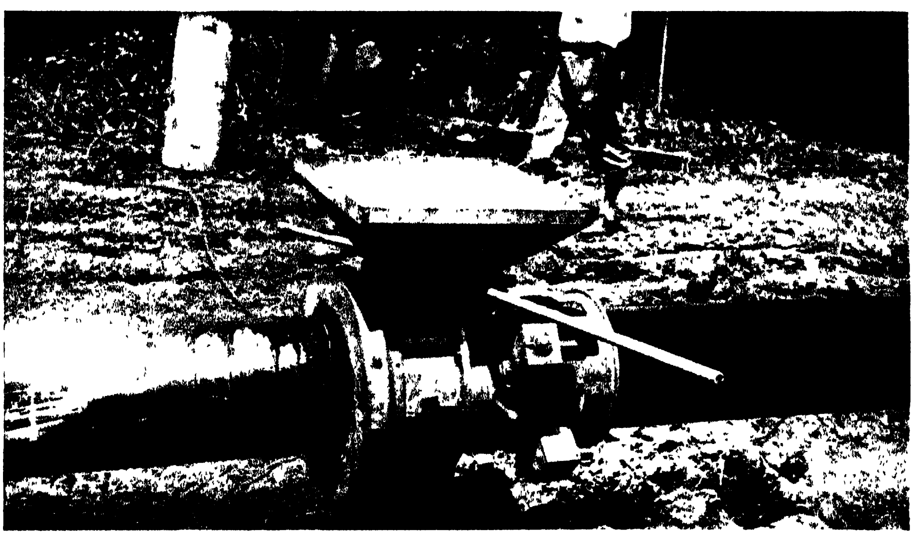


Fig. 7. Gardiner pipe coating machine

to compete with the electric motor drive has resulted in a compact engine-driven centrifugal pumping unit which will undoubtedly find extensive use for field gathering or relay stations. The high-speed engine is noisy, it has a higher maintenance cost, and is less dependable than the low-speed engine. On the other hand, this type of unit has the advantage of less weight and greater portability, less expensive installation, and a low first cost, which more than offsets the difference in operating costs. To these advantages should be added the adaptability of the engine for driving a centrifugal pump through a gear increaser.

The fuel-injection systems of the high-speed solid-injection engine are more sensitive to the type of fuel used than the low-speed air-injection engine, and, further, the corrosion of the parts of the injection system of the solid-injection engine results in serious operating problems when a corrosive crude oil is used as a fuel. The aluminium piston has not proved satisfactory in the high-speed engine burning crude oil containing hydrogen sulphide. Careful consideration should be given to the matter of the fuel available for the operation of the engine before it is purchased. At the same time the manufacturers should not overlook the urgency of correcting these faults. Although this type of unit might find its way into trunk-line service to take care of peak or temporary loads, its principal use will be found in field gathering or temporary stations.

Cooling-water Systems at Trunk-line Stations

About 7 years ago the Gulf Pipeline Company was confronted with the problem of using Diesel engines in a region where the water supply was small and poor in quality for cooling water. This problem was overcome by the installation of heat exchangers in the crude-oil suction lines of the discharge pumps to make use of the crude oil as a cooling medium for the engine-jacket water which was circulated through a closed system in which the heat exchanger was also connected. This development has proved to be one of the most important contributions in the use of Diesel engines for oil pipeline pumping service. This adaptation of the heat exchanger has made possible the use of the Diesel engine in regions and oilfields where the supply of water is very small and the quality of water is bad. It has reduced the operating and maintenance cost and minimized the number of shut-downs on account of cracked heads and other mechanical failures resulting from excessive heats. The loss of water from the closed circulating system is small and consequently the amount of water which must be added at various intervals can be supplied as rain or treated water, which will be free of scaling properties.

A number of such heat-exchanger installations have been made during recent years. The earlier installations were made at new trunk-line stations or when additions were made to existing stations. An important advantage of the heat exchanger in field gathering-station installations is that it simplifies the cooling system, reduces the time to build a station, lowers the first cost of the field station, and minimizes the loss in materials when the station is abandoned or dismantled. As a result of these advantages the heat exchanger has come into use to replace the old-type cooling systems for field gathering stations also.

The customary practice has been to make use of a low-pressure exchanger in the crude-oil suction lines. The crude oil passes through the heat-exchanger tubes and the engine cooling water is circulated around the tube bundles. Such installations can be made on the suction lines if the pressure drop across the exchanger does not interfere with the proper filling of the pumps by the natural gravity head from the height of oil in the pipeline working tanks; otherwise it is necessary to use a low-pressure booster pump in the suction line to overcome the friction loss across the exchanger to keep the pump filled. The limited pressure loss across the exchanger in this type of installation required a greater number of tubes to take care of the limiting friction loss and at the same time provide enough tube surface to take care of the low heat transfer due to the low velocity through the tubes.

One of the major pipeline companies has deviated from this general practice by installing high-pressure heat exchangers in the discharge piping of the pumping unit, thereby eliminating the use of the low-pressure booster pumping unit on the suction line, and simplifying the piping and operation. The first cost of the high-pressure installation is less than the low-pressure system with the additional advantage of eliminating the operating cost of the booster pumping unit. The high-pressure exchanger has proved just as satisfactory as the low-pressure installation.

The crude-oil piping for some of the first high-pressure heat-exchanger installations was not entirely satisfactory because sufficient provision had not been made to take care of the forces of contraction and expansion. After some failures in stiff connexions which could hardly be avoided, high-pressure 'groove and gasket couplings' were tried, but without success. It is believed that the problem has been solved by the use of long-radius vertical **S**-bends to connect the heat exchanger in the discharge line.

One of the first problems encountered in the use of the heat exchanger in closed systems for cooling the jacket water from Diesel engines was the corrosion of the tubes on the water side. In some cases electrolytic action between the metallic parts of the exchanger may result in corrosion, but generally the corrosion results from the presence of oxygen in the system or corrosive elements in the water. The closed system must be properly vented to reduce the oxygen in the system. Corrosion on account of the acid condition of the water can be greatly reduced by increasing the pH value of the water through the addition of alkaline substances.

An unexpected problem was encountered in the use of the heat exchanger in a closed system for types of engines having water-cooled pistons, which make use of telescopic tubes inside the crankcase. Experience shows that a small quantity of oil from the crankcase will find its way into the cooling-water system, which results in the accumulation of a coating of oil on the heat-exchanger tubes and consequently the lowering of the heat transfer which makes the system inoperative. In such a case special provisions must be made to prevent oil from the crankcase getting into the system through the telescopic tubes. Each engine should be considered individually in the selection of the type of cooling system.

The use of the heat exchanger in the closed cooling-water system eliminates the precipitation of scale on the cylinder jacket and in the cylinder and piston heads. The result is lower and more even temperatures of the cooling water, better lubrication on the cylinder walls, fewer breakages of cylinder and piston heads, and a lower maintenance cost.

Tanks at Trunk-line Stations

In the earlier days when the failures occurred frequently on the trunk lines between stations it was necessary to have as much as 100,000 bbl. of storage room at each station. As a result of this experience it became a customary prac-

tice to provide two 55,000-bbl. steel tanks at each station to check the oil between each station. Oil was alternately received and pumped out of the two tanks for checking purposes. When it was learned that this practice resulted in heavy losses of petroleum vapours by evaporation and in the paraffin going out of solution and being deposited in the tanks as a consequence of the loss of the lighter vapours, it was decided to carry one tank full of petroleum and allow the other tank to serve as a working or surge tank to take care of the increase or decrease in the pumping rate. The reliability of the trunk lines which has resulted from new welded lines and better maintenance schedules has made it possible to eliminate the use of one of the 55,000-bbl. tanks; however, some companies operating the lines at capacity during part of the year continue the use of the two tanks to provide a higher overall line capacity. The recent lines built by welding have sufficient reliability of line operation that it has been possible for the owners of such systems to operate with only a 20,000-bbl. floating-roof tank as a surge tank at each station. The recent 20,000-bbl. tanks which have been built at trunk-line stations are of electrically welded construction to eliminate the leakage which was experienced with the riveted tanks. Electric welding has been used for the construction of 55,000- and 80,000-bbl. tanks, and the results up to the present time have been satisfactory. The electrically welded tank is cheaper than the riveted tank. Floating roofs are usually provided for working tanks at trunk-line and, very often, at field gathering stations.

Automatic Tank Gauges

As an aid to simplify the work and reduce the operating expense, the efforts of some manufacturers have been directed to the development of an electrically operated tank gauge which can be used in the pumping station to take the gauge of the oil in the large crude-oil tanks. There is an instrument called the pneumercator which has been used successfully by some of the pipeline companies for gauging tanks as far away from the station building as 3,000 ft. The use of an automatic tank gauge is a great aid in the routine operation of a pumping station.

Use of Orifice Meters

The orifice meter which has been used for years in the gas industry has found a useful application in the operation of oil pipeline stations. Although the Venturi-type meter has been used for some years by one of the major pipeline companies operating in the Mid-Continent, the author has no information that the orifice meter was used to any extent in the oil pipeline industry before some companies were required to install meters on their lines transporting oil out of the Oklahoma City oilfield. The manufacturers of the orifice meter did not recommend it for even reasonable accuracy in metering oil. The experience of one company with the meters installed on its Oklahoma City 8- and 10-in. discharge lines convinced its engineers and operating men that the orifice meter could be used advantageously in their routine operations. It was learned that by exercising care in designing and making the orifice plate the meter will often check the actual pumpings. An error of less than ½% has been experienced. The meter has not been used by that company so much for the actual checking of the volume of oil as for observing any change or variation in the rate of flow. The principal use of the meter has been to determine whether a drop in the pumping pressure means a leak or break on the discharge line between the stations or some fault in the pumping equipment. Usually a drop in the pumping pressure means a leak or break in the line and is generally interpreted as such; however, a drop in pressure might result from the pump not filling, the pump getting air, a valve in the pump remaining open, or the engines missing or slowing down. If a drop of the curve on the orifice meter accompanies a drop on the recording pressure chart, the trouble is behind the meter and is usually in the pump. On the other hand, if a drop in the pressure occurs without any downward change in the orifice meter curve, the trouble is beyond the meter and indicates a leak or break on the discharge line between the pumping stations. On account of the drop in pressure when a leak or break occurs the engines are unloaded slightly, their speed will increase, and this might result in an increasing curve on the meter chart. The instrument will indicate promptly how to proceed to take care of the trouble. If the cause is behind the meter, the trouble can be checked quickly and remedied, and there is no need for sending line-walkers out over 40 miles of open country. On the other hand, if it is definitely known that there is trouble on the line, prompt steps can be taken to locate the leak or break to save the oil and prevent damage.

The orifice meter is especially useful in conjunction with centrifugal pumping units, since the increased output of the centrifugal pump with a break in the line might not, under some conditions, permit a pressure drop to be recorded on the recording pressure chart. An abrupt increase in the meter curve with or without a drop in the pressure curve would indicate a leak or break in the line.

The practical use of the orifice meter is exemplified by a case in which there was only sufficient pumping capacity in a station to deliver 56,000 bbl. at 700-lb. pressure. This pumping station was a central receiving station, and its crude-oil piping system was designed for pumping north and south. It was desired to move 47,000 bbl. of the oil south to a trunk-line station about 40 miles away, and 9,000 bbl. north at the least expense. A separate pumping unit could not be spared for the 9,000-bbl. delivery. It happened that there were four intermediate stations shut down on the trunk line north along a 240-mile stretch between the station from which the oil was to be pumped to the first operating station where the oil was to be received. It would have been expensive to have put in operation any of the intermediate stations for relaying such a small amount of oil. Calculations showed that 700-lb. pressure at the pumping station would deliver about 9,000 bbl. of oil through the 240 miles of intermediate lines. Theoretically, the plan was sound, but the practical objection was that in case of a drop in pressure at the pumping station it would not only be necessary to shut down on the 47,000-bbl. delivery south which was urgently needed, but there would be no way of telling where the failure occurred or whether the trouble was in one of the pumps. It would be necessary under such circumstances to have line-walkers go over not only the 40 miles south, but also the 240 miles north, which would involve a long shut-down and considerable expense. This practical objection was met by installing orifice meters on each of the two 8-in. lines going south, and on each of the two 8-in. lines going north. A meter was installed also on the 10-in. receiving line at each of the intermediate stations on the north line which were shut down. The meters fulfilled the requirement. When trouble developed in any of the pumps at the pumping station, all four orifice meters on the outgoing north and south lines showed a drop in the

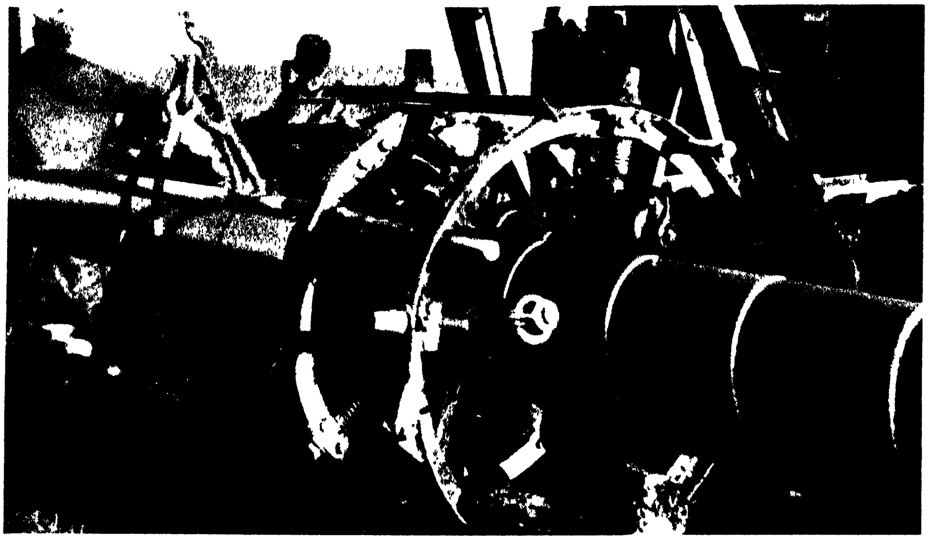


FIG. 8 The Johns-Manville wrapping machine

FIG. 9 Characteristic pitting of underground oil lines

FIG. 10. Temporary repair of pit leaks by use of a U-bolt clamp and gasket. Corrosion probably caused by oil from leaking couplings

meter curve with a drop in the pressure curve. When a leak developed on the north line an increase occurred on the meters north and a decrease on the meters south; a drop of pressure accompanied these changes on the meters. The meters on the intermediate stations north were used for determining between what stations the leak occurred. In this case the use of meters for checking any changes of velocity made possible the long-distance pumping and saved considerable expense.

Orifice meters installed on each end of the lines have been used to good advantage also in keeping a close check on the pumpings through old lines which are in bad repair on account of their economic status not justifying expensive maintenance.

Generally, the orifice must be inserted in the outgoing line at a place where it does not interfere with the passage of the pipeline scraper which is used for removing paraffin from the walls of the pipe. The installation would be very expensive if the meter were installed on a by-pass. The practice of one major pipeline company is to put the orifice directly in the line, providing a jack-screw flange to facilitate the removal of the orifice before scrapers are run. A concrete box around the orifice flange is provided to make it convenient for the workmen to remove the orifice plate.

Maintenance of Trunk Lines

The principal problem of the oil pipeline industry is the maintenance of the underground system of lines; the newer lines built of welded construction require little or no maintenance during the first 7 to 10 years of their life, but in due course of time a maintenance programme is necessary to meet the failures in the lines as a result of corrosion. On account of leaking couplings the older screw lines have required a continuous maintenance programme ever since the first day the lines were put in use. The older systems require not only the current maintenance on account of leaking couplings and corrosion, but also the removal, from the older lines, of leaking companion flanges, stuffing-boxes, collar-leak clamps, caulked couplings, defective right and left nipples, &c., which were used from time to time to make temporary repairs and which have accumulated during the history of the line. Such materials served the purpose of making temporary or emergency repairs. Although these devices proved expedient, they continue to leak and eventually their removal becomes necessary, especially since there are ways and means at present to make permanent repairs or replacements. This accumulation of repairs is no reflection on the men who have supervised and managed pipelines in the past; it must be remembered that the arts of an industry are accumulative, and are developed largely by experience.

The Use of Electric Welding for Repair Work

The advent of electric welding for pipelines, about 6 years ago, resulted in a radical change in methods of repairing oil pipelines. Although oxy-acetylene welding has been used for some time in the industry, it was not adapted to making repairs or to welding against the walls of a pipe which was carrying a moving stream of oil, or in which the oil was standing still; consequently, electric welding became a very useful art for welding leaking couplings, welding patches to the line, encasing leaking couplings and lines with sleeves, and depositing metal in the corrosion pits. Electric welding came into use at a time when the industry had decided to abandon the practice of reconditioning lines over their entire length and to confine their efforts to the repair or coating of lines in the places which were known to be corrosive.

This development effected an abandonment of the practice of removing from the ground long stretches of operating pipelines, placing them on skids over the ditch, cleaning them, and applying a coating. In the meantime the men have been trained to better workmanship; more knowledge has been obtained concerning corrosion; the adequacy and effectiveness of coatings have been determined; better methods of application have been developed; and the necessary equipment for carrying out this work under all conditions has been provided. The maintenance of pipelines, as far as corrosion is concerned, has been passing through a transitory period awaiting the development of the factors which have been enumerated above. This programme of repairing lines only in the 'hot spots', a term which is generally known in the industry as an area which is subject to active corrosion and where the pipe has deteriorated, is still in effect. It is a programme of patching rather than replacing pipe.

Corrosion of Underground Lines

There are many unexplained causes for the corrosion of underground steel oil trunk lines, because there are so many factors involved—especially in pipelines that traverse great distances and encounter all kinds of conditions along their route. Practical pipeline men recognize some of the following general causes of the corrosion of these underground lines:

1. Various types and degrees of subsurface soil corrosion.
2. Stray electric currents.
3. Miscellaneous conditions on the pipeline right of way along its route.
4. Oil leaks.

Repair of Pit Leaks

It is general knowledge that if a piece of unprotected steel is buried in the ground it will deteriorate; and, perchance, if there are any corrosive elements such as cinders in the soil an accelerated deterioration will occur. The same thing happens in the steel of a pipeline, except that, instead of the surface wasting evenly over its whole surface, the corrosion usually concentrates itself in small areas—resulting in 'pits' that in time become sufficiently deep to penetrate through the wall of the pipe, causing an oil leak. Fortunately, many of the holes at the base of the pit are not large; however, the oil loss and damage resulting from a single pit is appreciable. Corrosion ranks first not only in cost, but also in the time required to maintain lines. The characteristic pitting of underground lines where there are bad corrosive soils is shown in Fig. 9.

When a failure occurs in the pipeline as a result of corrosion (which means a pit through the pipe), it is found either by the line-walker, who covers the line on a regular schedule, by a drop in pressure at the pumping station, or by the volume of oil checking short at the next receiving station. There are occasions when the leak on the line is rather small and, consequently, a drop in pressure will not occur, and it cannot be found in the volume of oil; but over a period of time an appreciable amount of oil will be lost. Only the line-walker can find such leaks. Six years ago it was customary to repair such leaks by putting on a heavy cast-iron saddle with a gasket over the pit in the pipe. If the pipe was badly deteriorated, it was cut out of

the line in due time. A temporary repair was always made, of course, with the saddle clamp—until such a time as the line could be prepared for drainage and replacement of the pipe. In more recent years the practice of repairing corroded pipe pits has changed, and the usual procedure for the repairing of a small pit is to drive a wooden plug into it to prevent the leaking of oil, and then to place over it a small steel patch clamped to the pipe with a gasket between the pipe and the clamp. The installation of such a patch can be done by one man. Such a job is temporary; in due time the patch is electrically welded to the line, provided the pipe surface surrounding the pit will permit of welding, and provided the pipe itself will not have to be replaced. This repair is an example of the valuable use of electric welding in combating the corrosion problem (Fig. 10).

The Use of Patches, 'Slabs', and 'Half-soles'

One of the handicaps in maintaining pipelines has always been that there has been no practical way of taking care of the oil drainage along the line, and it has always been

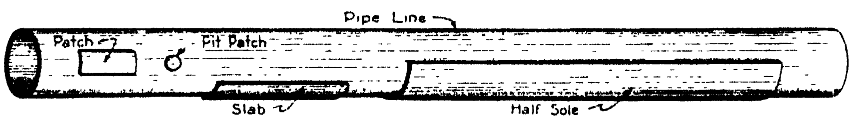
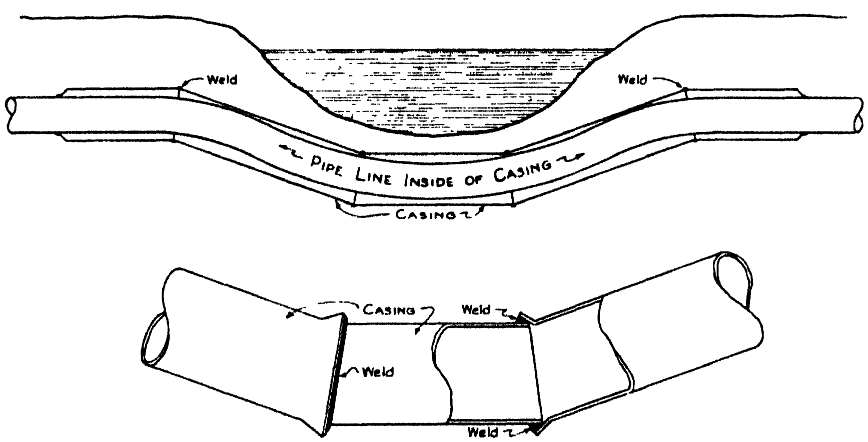


FIG. 11.

a slow and inconvenient procedure to transfer the oil from one line to another parallel line. This problem will be discussed later under another heading; but it should be mentioned here that this handicap in pipeline maintenance, coupled with the necessity of keeping lines to capacity during recent years, has been a material factor in bringing about the present practice of patching lines.



DETAIL OF JOINT

FIG. 12.

If a pit leak occurs, it is repaired in the manner described above, but an inspection of the whole surface of the joint of pipe will be made when the pit leak is repaired. If it is found that there are large areas on the pipe which are deeply pitted also, a patch sufficiently large to cover the area will be cut from a piece of pipe of the same diameter. The patch is pressed into position with hydraulic jacks, so that the inside curvature of the patch will fit the outside curvature of the pipe to be repaired. After the patch is tacked to the line, it is electrically welded to the line around all edges and the U-bolt clamps are removed. Some companies have put on as many as three or four on a single joint of pipe.

The bottom of the pipe is often badly pitted where it rests firmly against the soil making good electrical contact with the moisture, while the upper half of the pipe is in good condition. Rather than replace the pipe, which would require a long shut-down to take care of the drainage, some companies have followed the practice of 'half-soling' the joint. This procedure is similar to the use of the patch, except that in this case the patch becomes a half-sole, since it is cut almost large enough to cover the lower half of the pipe over the whole or part of the length of the pipe. The edges of the half-soles are electrically welded to the pipe in the same fashion as the patch. If the corrosion is limited to the bottom of the pipe, only a 'slab'—which is similar to the half-sole, except that it does not cover as great an area of the pipe—is electrically welded to the pipe.

Casings

An inspection of the pipe in dry or shallow creeks, water courses, and swamps often reveals that the pipe is in bad condition, and should be replaced with good pipe. Operating conditions may not permit the necessary shut-down time to drain the line. In such cases many companies have resorted to the use of a large casing over the pipe. A straight casing can be used sometimes, but very often, in the case of creek crossings and water-courses, it is necessary to make use of a mitred casing to fit over the sags. The casing of the line is done by splitting a larger piece of pipe into halves, swaging it down at the ends, and fitting it over the smaller line. The length of the casing is electrically welded along the longitudinal seams, and the girth joint is welded to the pipe. The procedure—except that the casing is usually straight—is also used sometimes when existing lines must be cased across newly constructed roads (Fig. 12).

Spot Electric Welding

Soil corrosion results sometimes in only a few pits scattered over the surface of the pipe. If the pits are not too deep, spot welding has been used. This procedure involves the filling of the pits with a deposit of welding material through the use of the electric arc. Care must be taken that these pits are not too deep, on account of the arc burning through the wall of the pipe. In some cases a small plug of steel is fitted into the pit, and the metal is deposited with the electric arc to fill the corroded area. This work has been done with the line filled with oil and, in many cases, with the line in operation. It should be kept in mind that only the electric-welding arc is used for this class of work.

Repair of Leaking Couplings

Repair of leaking couplings ranks second in the maintenance schedules of pipeline companies operating screw and coupling lines. A thread and coupling joint in any system of pipelines is susceptible of developing leaks, and this is especially true of oil pipelines, because rather large diameters are involved, and the joints were made under the

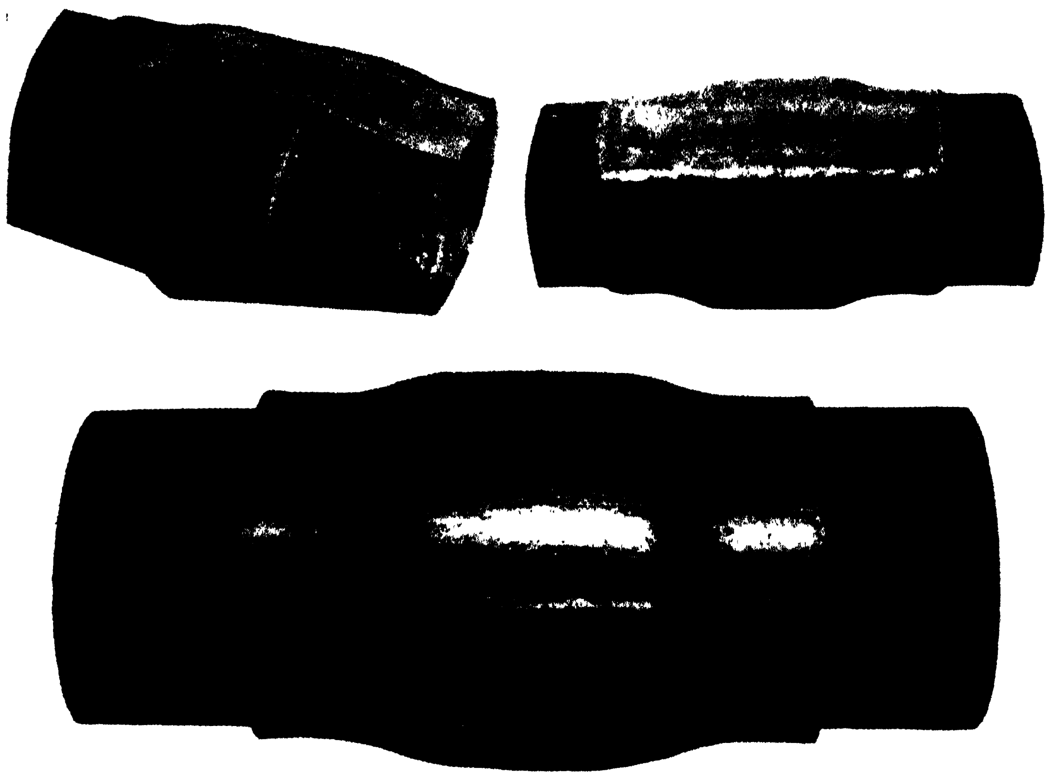


FIG. 13 Split sleeve in place ready for welding

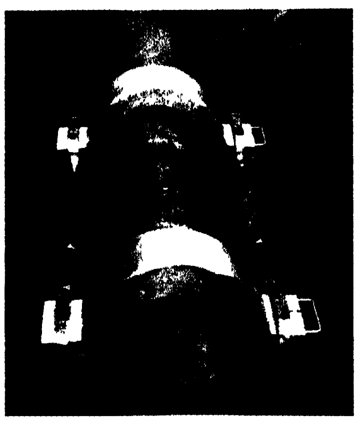


FIG. 14. Safety jig for welding couplings

conditions of pipeline construction which were not favourable to making a tight and satisfactory joint. There may be more than a few causes contributing to the leaking of the joint, but cross-threading, or the damaging of the thread when it was screwed into the coupling, has caused many of the leaks. Out-of-roundness of the pipe or coupling is another factor. In the operation of the line coupling leaks may occur after the operating pressure has been reduced, especially if the line has been strained by an excessive operating pressure. The contraction or expansion of the line during temperature changes effect a stress in the coupling which results in a leak that may be so small that the oil will not come to the surface of the ditch, or so large as to cause a pressure drop at the pumping station.

The customary practice of repairing leaky couplings has, for years, been the caulking of the coupling by the line-walker or repair man. This method involves peening the metal of the coupling back against the threads by means of a caulking tool and hammer. If the leak could not be stopped by the use of caulking, it was the usual practice to put on a collar-leak clamp, which is a familiar piece of equipment in the pipeline industry. It is not uncommon for couplings to spring leaks which cannot be repaired either by caulking or the collar-leak clamp, and in such cases the regular stuffing-box clamp was used.

These practices are still used in the pipeline industry, but to a much lesser extent than before the use of electric welding. Under present practices a leaking coupling may be caulked as in the past, but it is the usual practice of some companies to install a collar-leak clamp as a temporary repair. If the leak is too bad to permit the use of a collar-leak clamp, it is necessary to resort to the old practice of using a stuffing-box. A few years ago leaking couplings were repaired by caulking the edges of the coupling and welding a sleeve over the entire coupling. The sleeve consists of two halves of a piece of pipe forged to fit over the coupling (Fig. 13). The longitudinal as well as the girth seams are welded electrically. Some companies make use of a split ring or 'chill band' 1½ in. wide and ¼ in. thick, instead of the collar sleeve. The ring is made to fit against the face and flush with the outside of the coupling. The top edge of one side of the ring next to the coupling is bevelled slightly for welding the ring to the coupling. First, the ring is tacked to the pipe and a small bead is made to weld the ring to the pipe. Next, the ring is tacked and welded to the coupling. The second welding beads are then made for strength. The ring has the advantage of being much less expensive than the sleeve, and has the advantage over the direct welding of the coupling in that the heat of the electric welding arc is kept away from the threads. If the conditions of the coupling will permit, the general practice now is to clean thoroughly the recess between the threads and the coupling and to electrically weld the coupling to the pipe on both sides without the use of a sleeve. As a safety measure against the pulling of the threads out of the coupling, one of the major companies has designed a special collar-welding jig which is shown in Fig. 14. The jig is made of duralumin and high-tensile steel to keep down the weight. This jig has been used and found practical as an excellent safety precaution. In welding couplings, bell holes should be used for each coupling rather than the placing of a length of line on skids. The reason for this procedure is that if the line is left undisturbed in the ditch it is less liable to have strains put on it which might cause the pulling of the thread out of the coupling. In making this repair, as well as the others which have been described, a carbon-dioxide fire extinguisher is kept available so that there is no delay in making use of the extinguisher if necessary. Although sleeves have been welded over couplings which were leaking so badly that they could not be caulked to stop the leak for the welding operation, it is a hazardous and unsatisfactory repair at best. It is better to put a collar-leak clamp or stuffing-box on such a coupling until such a time as the line can be spared for cutting the leaking coupling out of the line. Very often a sleeve welded over a leaking coupling develops a leak itself as a result of the internal pressure; the writer's opinion is that the sleeve will cause additional work in the future, and it is not a very satisfactory repair job.

It should be pointed out that in making repairs on loaded oil-lines electric welding is used as the oxy-acetylene method is not adapted for this class of repair. This statement is emphasized out of fear that some person unfamiliar with the practice might undertake a repair job which might result in an accident.

The experience of the pipeline companies has been that the thread and coupling line involves continuous repairs. If one leaking coupling is repaired, it is just as likely that the strain will be taken up in the next joint, and a leak will develop in the next thread and coupling. There is no question that the thread and coupling line is obsolete and is difficult to maintain. One of the most disconcerting features of the leaking coupling has been that very often the oil does not come to the surface of the ground, and, as a result, the oil which leaked from the coupling remains in the ditch to contaminate the soil adjacent to the pipe, which results in serious corrosion of the pipe.

Résumé of Patch Repairs

Without the use of the electric welding arc, the patch work described above could not have been done, and it would have been necessary to drain the line, cut out the pipe, and replace the old with new pipe.

The use of the patch and gasket over pit leaks has served not only as a quick and inexpensive repair, but also as a very satisfactory method. The electric welding of couplings has proved satisfactory, but the use of the large patches, half-soles, pipe casing, and collar casings have not been entirely reliable. Leaks have developed under the large patches, half-soles, and in the casing, and the patches have not held against the pressure.

There is an economic limitation to the use of half-soles, slabs, patches, and casings, because it has been learned that in many of these cases a pipe replacement can be made at less expense, and a more satisfactory job is obtained.

The use of the electric arc in making these types of repairs has become so promiscuous that there is a considerable element of danger involved. There will be a continued need of this type of repair—even though it is considered temporary in nature, and there will be an economical use for the electric welding of patches, couplings, and small pit patches. It is apparent that there will be certain risks involved, especially in welding couplings, and every precaution should be observed to safeguard the lives of the welders and the workmen. The Safety Committee of the American Petroleum Institute has prepared a code of precautions to be observed in such work. The responsibility for carrying out this class of work rests rather heavily on the shoulders of operating men, and only constant vigilance on their part will prevent serious accidents in making such repairs by welding. Most companies make

these repairs on the lines while they are in service under pressure. It is preferable to take the line out of service if repairs are to be made on the high-pressure part of the line—it is less dangerous in case of a failure. The welding of couplings and the use of small patches will be warranted, but the practice of making such extensive use of patches, slabs, and half-soles cannot continue long without these lines becoming badly patched, and that is not a good maintenance programme. This class of work will continue to serve as an expediency in keeping in service lines which cannot be spared for repairs, but eventually replacements will have to be made, and the continued practice of patching only adds to the burden of the maintenance of these lines in future years. Very often it is more economical to make pipe replacements than to make the miscellaneous repairs on the old pipe.

A successful maintenance programme on a large pipeline system depends on the field men reporting all leaks and breaks as well as inspections which are made from time to time. Such reports must be made in some systematic way, and it is imperative that suitable forms be provided for reporting to the general office, where a careful record is kept, usually in the engineering department. The reports are usually made by the connexion foreman through his district foreman or superintendent, and it is important that the field men be trained in the proper use of the forms which are supplied them. A complicated and expensive system of making and keeping records can easily be established without practical results, and diligence must be observed to keep records within practical limits. The scope of this article will not permit one to go into the details of the forms and records.

Mile-post Markers

Accurate reference points along the pipeline, especially the trunk lines, must be provided to enable the field men to report definitely the locations of leaks, breaks, repairs, and reconditioning jobs. Mile-post markers are set on most pipelines. It has been learned by experience that it is not only inconvenient, but too much time is required by the field men to tie in the locations with mile posts, and this condition encourages the men to estimate rather than measure the distance; to meet this condition a brass tag $1\frac{1}{2}$ in. wide and $3\frac{1}{2}$ in. long, stamped with the company name, has been designed. These tags are nailed at a certain place on a prescribed fence post where the lines cross each property line. The inventory distance on the line is stamped on the tag with a steel stencil, and the tag is nailed to the fence post by the civil engineers when they make their measurements. The use of the inventory tag on the property fence posts has aided materially in obtaining accurate records.

Inspection of Lines

Many oil leaks from corrosion can be prevented if the field men, especially the line-walkers, are trained in a practical way to observe and report conditions which may result in the corrosion of the lines. The field men, from the superintendents to the line-walkers, should be coached concerning the practical corrosion problems and trained to observe conditions along the line. Line-walkers should be provided with an 'A-B-C' instruction paper on corrosion of pipelines and told in his own language the miscellaneous causes of corrosion along a pipeline. Each line-walker should have a note-book to record his observations and report them to his connexion foreman. These two men should be made responsible for conditions along their section of the line. Such a plan should bring about valuable results.

An important part of a maintenance programme for oil pipelines is an inspection of the lines at places where the records, practical observations, and experience point to corrosive conditions.

During the past 2 years a major company made a thorough inspection of the trunk lines where they cross watercourses, streams, and creeks, also in the banks of the creeks. As a result of these inspections a considerable amount of pipe in such places has been replaced already, and others will be changed according to a schedule. This procedure has effected real savings and brought about better operating conditions. Such a programme is warranted because repair jobs in such places can be done only under favourable conditions; otherwise, the jobs might be expensive and, in addition, a large loss of oil and damage might occur. An emergency repair job done at such places during unfavourable conditions may result in a long shutdown.

Records and experience indicate that corrosion of the lines can be expected under the following conditions:

Outline of some Known Causes of Corrosion of Oil Pipelines

(*a*) Oil leaks.

(*b*) Natural soil corrosion:
1. Alkali soils.
2. Tight soils that hold moisture such as clay and gumbo.
3. Marsh and swamp land.
4. Drainage or watercourses and ditches.
5. Fills or dumps of mixed soils.
6. Creeks and creek beds.
7. Ponds.
8. Any condition which subjects line to alternate wetting and drying.

(*c*) Oil- or gasfield refuse:
1. Salt-water areas.
2. B.S. ponds.
3. Slush pits.

(*d*) Acids:
1. Cinder fills.
2. Refinery waste.
3. Barnyard drainage.
4. Hog-pen drainage.
5. Sewerage disposal.
6. Mine and smelter drains or dumps.
7. Dumps or rubbish.

(*e*) Decaying vegetation:
1. Wood thrown in pipeline ditch.
2. Tree stumps and roots in pipeline ditch.
3. Any foreign material in ditch.
4. Straw or hay stacks.
5. Manure piles.

(*f*) Artificial:
1. Road crossings and road ditches.
2. Railroad rights of way and barrow pits.

(*g*) Electrolytic:

Stray electrical currents from electric railroads or from other pipelines may cause severe corrosion.

Such a list should be given the field men to guide them in their observations.

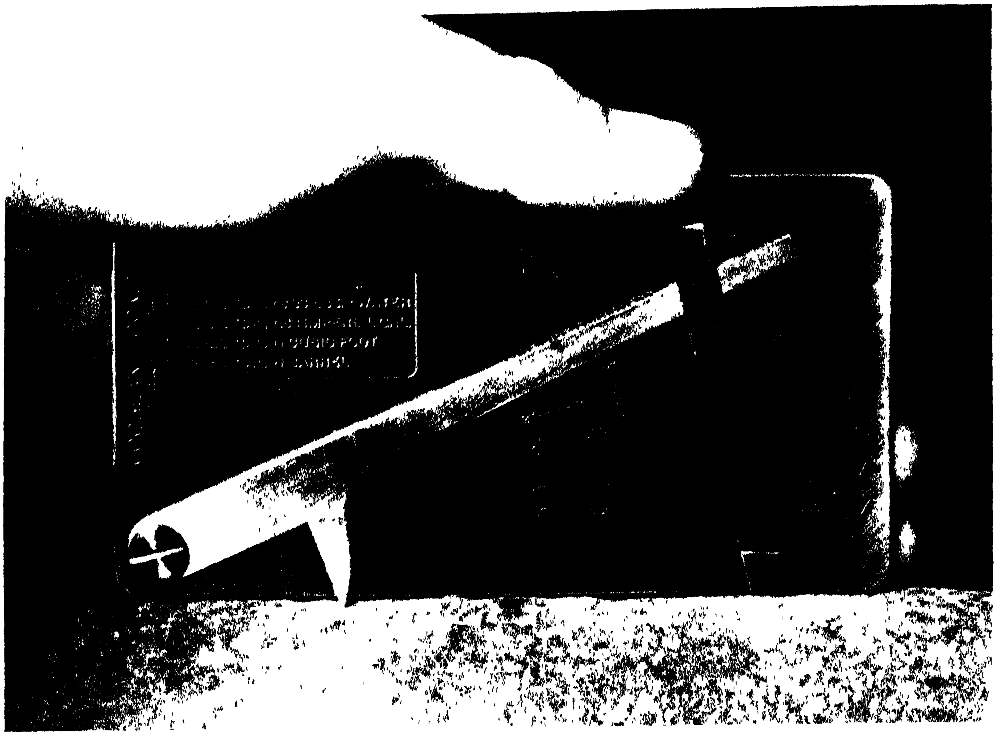


Fig. 15 Measuring pits in pipe with the pit gauge

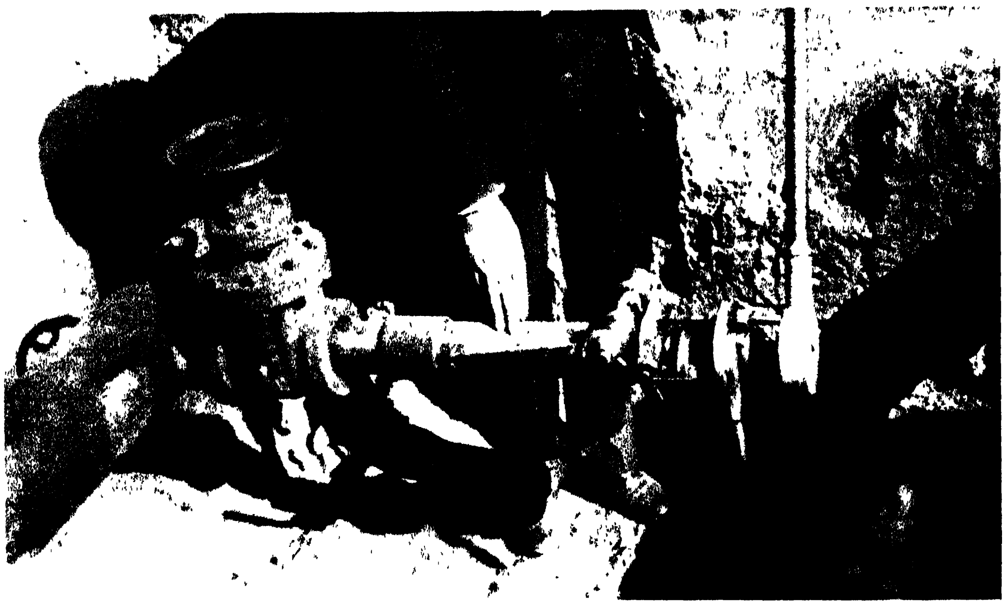


Fig. 16. Tapping equipment used preparatory to transferring oil from one line to the other

Oil leaks result in a type of corrosion which accounts for a high percentage of pipeline repairs. If a leak occurs in a soil of tight texture and the drainage is poor, a serious corrosion of the line will occur within a period of 4 to 7 years. Unfortunately, many small leaks from couplings never come to the surface of the ground, and there is no way of anticipating the corrosion from this class of leak. It is the practice of most pipeline companies to remove oil-soaked ground from the ditch and replace it with uncontaminated soil. The line in areas where old oil leaks have occurred in the past is inspected for corrosion.

The Depth Gauge

In coping with the corrosion problem of underground lines it is important that the men who are engaged in the maintenance of lines have a simple means of measuring corrosion pits, because the men must have a common language not only for reconditioning lines, but also for the classification and salvaging of second-hand pipe. A simple depth gauge could not be purchased, and, consequently, C. M. Scott, Chief Engineer, and J. C. Stirling, Corrosion Engineer of the Stanolind Pipeline Company, developed such a gauge which has been put in the hands of the superintendents, district foremen, connexion foremen, and welders of that company for the use of these men in repairing and reconditioning lines, as well as for salvaging pipe. This simple device has standardized the judgement of the operating forces in this matter and has facilitated the making of decisions in cutting out pipe, repairing lines, and salvaging pipe. This gauge has proved valuable because it is so simple and, at the same time, sufficiently accurate for practical purposes. Such a gauge can be used and read by the average workman, who cannot understand the type of depth gauge which engineers use (Fig. 15).

Operating Precautions in use of Old Oil-lines

There are many old lines which cannot be repaired because their economic status is too uncertain to justify large expenditures for their maintenance. The obsolescence of the older screw and coupling line is another reason for limiting the expenditures in the maintenance of such lines. An example of lines in this category is a 6- or 8-in. lap-welded screw and coupling line which has served an oil-producing area for 15 or 20 years and is required to handle only a small amount of its capacity on account of the small amount of oil production in the field it is serving. To meet these circumstances, one company has planned to test these lines each 6 months by raising the pressure over the entire line 200 lb. above its normal operating pressure. The pressure on any part of the line is kept below 700 lb. The pressure on the line is raised by by-passing the oil at the delivery end of the line through an orifice which has been designed to raise the pressure 200 lb. at the low-pressure end of the line. This increased pressure of 200 lb. is transmitted back over the entire length of the line to the pumping station. If the station operates normally at 400 lb., the increased pressure of 200 lb. caused by the orifice at the other end of the line will result in an operating pressure of 600 lb. at the pumping station. Each 6 months the old lines will be tested at the increased pressure over a 24- to 48-hour period. During the test line-walkers will cover the line to look for leaks developed by the higher pressure. It is believed that the increased pressure will find the weak spots which can be repaired promptly under good weather conditions and with small losses of oil. The line should operate without leaks between the 6-month tests.

Problem of Draining Lines

One of the most perplexing problems in the maintenance of oil pipelines is the drainage of oil for the replacement of pipe. This is one of the principal reasons why pipe replacements are not made unless it is absolutely necessary. The present practice of patching lines can be attributed largely to this problem, along with the fact that the lines could not be spared.

In the case of single lines, and for multiple systems also, it has been necessary to excavate a large earthen pit along the right of way, or to provide a dam in some low part of the right of way to store the oil which was drained from the lines. A large amount of the oil soaks in the ground, and much of it is lost by evaporation. There is the danger of rain washing the oil away. The oil stored in the earthen pit is a fire risk. Damage to the land results from storing oil in pits or dams. The building of the dam or the excavating of a pit sufficiently large to hold the oil is expensive. There is also the added time and expense of pumping the oil back into the line.

If a parallel line were available, the old practice was to install saddle connexions with stop-cocks or gates to transfer the oil from one line to the other. A portable reciprocating pumping unit, known in the industry as a 'pick-up' unit, was used to transfer the oil. Such a pumping unit had a capacity of 60 to 100 bbl. per hour. At this rate of pumping too much time was required to transfer the oil. During the period the oil was being transferred the pressure on the operating line was reduced and, consequently, the line capacity was lowered. This method made it necessary to leave the saddle and connexions on the line, which is undesirable on account of the risk of losing oil by leakage from connexions, or the blowing out of the gasket, or the breaking of the valve or stop-cock. An accumulation of temporary repairs on the older lines was the result of this inconvenience of draining the lines.

Tapping Lines

To meet the objectionable features of leaving a saddle connexion on the line and to facilitate the operations of transferring the oil, a new type of tapping machine and connexions were developed by Superintendents J. E. Polston and A. M. Hill of the Stanolind Pipeline Company. This equipment is shown in Fig. 16.

The first step in making the transfer of the oil is to weld electrically a specially designed forged-steel nipple to the line which is to be drained, and also to the line into which the oil is to be transferred. This special nipple is a steel forging with a heavy wall. One end is shaped to fit the curvature of the pipe, and the other end has a special thread on the inside and a standard 3-in. thread on the outside. After these special nipples have been welded to the line, a high-pressure 3-in. gate valve is screwed on the nipple. The tapping device with a stuffing-box is screwed to the other end of the valve. The valve is opened and a 2½-in. hole is drilled through the pipe by a drill fitted to a drill-shaft which is operated by the ratchet-type tapping device. After the line is tapped the drill is withdrawn and the valve is closed. The tapping device is disconnected from the valve to make the connexions for transferring the oil. When the transfer of the oil has been completed, the tapping device is screwed into the valve again for the purpose of screwing a specially designed solid forged-steel plug into the inside thread of the nipple welded to the line. The head of the steel plug fits the shank used for the drill, and the same operation for tapping the line is used, except

that instead of drilling, the plug is screwed into the nipple. After the plug is tested for tightness, the tapping device is unscrewed and the valve is removed. A 3-in. coupling and bull plug are screwed to the outside thread of the nipple which was welded to the line. The inside plug prevents any leakage, and the outside bull plug is provided to preserve the working features of the inside plug for future use. The outside bull plug and coupling are coated with asphalt to protect them against corrosion. A record of all such connexions is made on the line maps for reference so that these connexions can be used again when the drainage of the lines may be necessary in the future. Some of these connexions have been made on lines at the foot of long drainage areas for no immediate use, but for future service.

Drainage or 'Pick-up' Pumps

The old-style pick-up units which had been used for transferring or draining oil were not only too small in capacity, but very slow and cumbersome in moving them over the roads. Such units were usually equipped with iron or solid rubber-tired wheels, and, consequently, the speed at which they could be moved over the highways was limited. Hours were required to assemble the suction and discharge piping before the oil 'pick-up' unit could be put in operation. Light-weight centrifugal pumping units were tried out as replacements for the old-style 'pick-up' unit. The operation of a centrifugal pump was not understood by the pipeline workers, and this type of 'pick-up' unit has not been as reliable and fool-proof as the piston-type reciprocating unit. After years of experience with oil pick-up units one company decided to return to the use of the piston-type reciprocating unit, providing new features to speed up the movement of the unit over the highways and to facilitate making the connexions in the field for transferring the oil. Fig. 17 shows such a unit mounted on a trailer. The suction and discharge piping is assembled complete with a by-pass valve between the suction and discharge line. There is a check valve and strainer in the suction piping and a check valve in the discharge connexion. The piping is grooved for victaulic couplings, and flexible steel hose is provided for the suction and discharge line. The size of the discharge line is 3 in. and the suction line is 4 in. A pressure gauge is provided for the discharge line and a combination low-pressure and vacuum gauge for the suction line. The trailer is equipped with pneumatic tires. The pump has the following capacities:

93-bbl. hr.	600 lb.	3-in. liner
150 ,,	400 ,,	4 ,, ,,
250 ,,	250 ,,	5 ,, ,,

The pump is made so that interchangeable liners can be used. The pump is direct connected through a worm drive. The 50-h.p. gasoline motor is equipped with a clutch. By the use of a flexible steel hose no fittings are required, and the joints are made by means of the groove and gasket coupling. Thirty to 40 minutes are required to connect the unit, ready for transferring oil; whereas 4 to 5 hours are required to connect a pick-up unit with the cast-iron fittings.

The Use of Concrete Plugs and Compressed Air in draining Lines

In the case of a multiple system of lines it is possible to transfer the oil from one line to another, but a different arrangement must be made for single lines. Since it was recognized that the draining of the oil into earthen pits was not only expensive but dangerous, one company has used, with success, two methods for displacing oil in a drainage area where pipe must be replaced.

For large drainage areas this company uses a method which makes use of a concrete plug, formed by forcing into the oil-line, under pressure, a quantity of quick-setting concrete in the proportion of 1 part cement and 3 parts sand. The concrete is a moderately fluid mixture. The plug may vary from 8 to 12 ft. in level pipe, and considerably less, of course, in a sag. The pipe can be stripped, raised above the ditch, and sagged between skids to obtain a short plug. The concrete sets within 12 hours, and is ready for use at the end of 24 hours. The drainage nipples, which have been described above, are welded to the line on either side of the concrete plug; the line is tapped, and the oil is transferred from one side of the plug to the other by the pick-up pumping unit. After the line has been drained on one side, it is cut and the bad pipe is taken out, and a high-pressure gate valve installed in the drained line with forged-steel flanges. One of the nipples used for draining the line has been welded beyond the gate valve and connected for transferring the oil from the other side of the concrete plug into the line beyond the closed valve. With all the oil transferred, the bad pipe is replaced with new pipe which is flanged into the open end of the gate valve that is left in the line. Another drainage-plug nipple is welded on to the new pipe, at a suitable distance from the valve, to take care of future drainage in this area. The concrete plug holds against 200 lb. pressure before any leakage develops. This method is used only for long-drainage areas of single lines, 6 in. or larger in diameter. To eliminate the necessity of leaving a valve in the line, the use of an asphalt plug has been described by the author [2, 1934].

For the smaller drainage areas compressed air is being used successfully for displacing the oil from single lines. A description of the method requires a long discussion which cannot be included in this article.

Equipment Buildings

As long as the pipeline industry was using only hand tools, a small tool-house or warehouse provided sufficient room for the storage of materials and equipment. During the years when the pipeline industry had been going from hand tools to machinery, much of the equipment—such as the 'pick-up' pump, tractors, trailers, tar pots, compressors, &c.—was stored outdoors, usually along the property fence. The need of equipment buildings for the storage of materials and the care of equipment has been recognized. Buildings, of the type shown in Fig. 18, have been built by one company at different divisional head-quarters for pipeline crews. Such buildings have been of material value in carrying out a programme for training the workmen and foremen to take good care of their materials and equipment. The building is of steel framework, with corrugated galvanized-iron sheets for the roof and walls. The foundations and floors are made of concrete. There are eight stalls for the storage of equipment—with a shop at one end, and a room for the storage of tools and materials at the other end. These buildings cost about $4,000 each. Experience indicates that such buildings are necessary for carrying on effectively maintenance programmes on pipeline systems.

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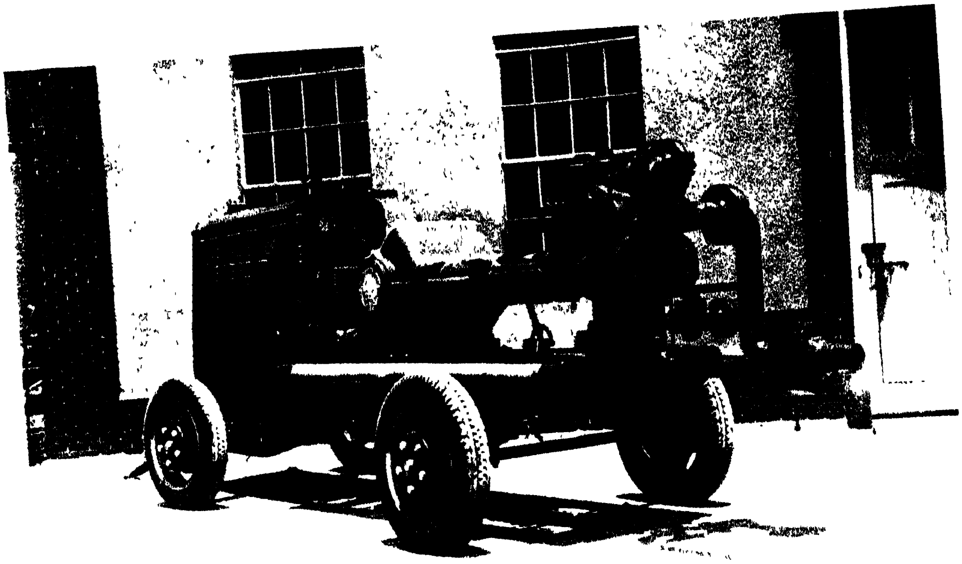

FIG. 17. Modern oil 'pick-up unit'

FIG. 18 A typical gathering station 'of yesterday'

DESIGN OF MAIN-LINE PUMPING STATIONS

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A FEW years ago the designer of a main-line oil-pumping station had little choice of main units. Steam boilers with steam engine and oil pump combined were practically standard, being the only units available for the duty. Since the War, and notably in the last 6 to 8 years, the possible choice of plant has increased so much that often the final decision on the design of pumping stations depends to a great extent on personal likes and dislikes.

The reciprocating pump no longer holds a position of commanding pre-eminence. The use of centrifugal pumps has established the fact that they may be almost as efficient. They are cheaper both in the first cost and in maintenance costs than the reciprocating type. Furthermore, they require lighter foundations and, in some ways, are more versatile, and can be more easily moved than the old heavy type of slow-moving reciprocating pump.

Turning to the motive power required to drive the pump, steam is eminently suitable for driving the reciprocating pump, but it has the disadvantage of requiring boilers, with their maintenance troubles. As pipelines are often laid in places where water is expensive and thoroughly bad, the costs of the boiler and engine maintenance are high. Moreover, the first cost of such an installation is also very high. However, in these days, the designer of main-line stations has the further choice of Diesel engines, or frequently another alternative, electric motors; and with the centrifugal pump he has the further possibility of using a steam turbine.

Choice of Pumps

The first and fundamental question to be decided in the design of new pumping stations is the type of pump to be used. The double-acting reciprocating pump, duplex or triplex, is suitable from a technical point of view for handling almost every problem possible: the centrifugal pump, on the other hand, has definite limitations. The reciprocating pump can be made to handle oil of any viscosity. The centrifugal pump becomes more and more unsuitable as the viscosity of the oil to be handled rises. There is no fixed point that governs this as the volume and head are also important factors, but in any circumstances the viscosity must be well under 300 seconds Redwood to justify the use of centrifugal pumps, because the drop in efficiency as the viscosity of the oil rises is much greater with centrifugal pumps than with reciprocating pumps.

This close dependence on viscosity may mean that, where climatic conditions cause big temperature changes in the main-line fluid at a point where the viscosity of the main fluid changes sharply, centrifugal pumps although having a good efficiency in hot weather may in cold weather have a very much lower efficiency, even to a prohibitive degree.

Another important factor in the choice of pumps is the ratio between the throughput and pumping head. The higher this ratio, the more probable it is that centrifugal pumps may be suitable, i.e. the larger the capacity of the pump and the lower the head against which it has to work, the more probable is it that a centrifugal pump will show up well against a reciprocating pump. On the other hand, the reciprocating pump still has the advantage in efficiency. With units that are now considered for main-line pumps, i.e. with pumps of a capacity of 15,000 barrels per day or more, an overall efficiency of 88% to 92% can be obtained, covering the reciprocating pump and a set of single reduction gears. Conditions have to be very favourable indeed for centrifugal pumps to give any efficiency better than, say, 83%. A more common efficiency that can be expected is in the neighbourhood of 78%, and that figure is probably above the average even for main line pumps.

Leaving the technical side for a moment, other aspects have to be considered before a final choice of pumps can be made. The last few years have shown that, on many pipelines, it is not certain that commercial considerations will allow of their working at a set throughput for 365 days a year for many years on end, and, therefore, efficiency and running costs may not be the only important points to be considered. If main-line stations are to stand idle, i.e. without earning any standing charges, let alone profits, it may be better for capital costs to be low rather than efficiencies high. Such conditions favour the centrifugal pump. The proportion of duty to weight of equipment for such high-speed units is much less than the same ratio on the large heavy slow-acting reciprocating pump, and so their first cost is lower. Furthermore, light high-speed revolving machinery in perfect balance requires less foundation work, and finally both the time and money required for dismantling and removal to another site are less.

It will thus be seen that, in many instances, no hard-and-fast rule can be laid down between reciprocating pumps and centrifugal pumps, without attention being paid to factors outside purely technical considerations.

For flexibility with certain forms of drive, the centrifugal pump again shows up very well compared with a reciprocating unit. (Refer to Fig. 1, which shows the characteristics of a single pump and two pumps in series.) It will be seen that both for a single pump and for two pumps in series the efficiency curve plotted against head and throughput is of the same type as, and closely approximates, the curve connecting pressures and throughputs in pipelines. If speed variation is possible, this theoretical advantage is translated in practice into the fact that over a large range of throughput and pressure the pump units are working near or at their highest efficiency. There is also the advantage that the maximum possible closed-in pressure is not far from the working pressure. This means that no relief valves are required against accidental throttling, or even closure of valves against the pump. Complete closure admittedly would cause the pump to heat up dangerously in a few minutes. With reciprocating pumps, however, in the absence of relief valves, such closing of valves against the pump would mean the immediate disclosure of the weakest link by failure.

A certain amount of flexibility can be obtained with reciprocating pumps, not only by varying their speed, but also by changing the sizes of plungers. Such provision calls for attention in choosing the capacity of the prime mover. If it is intended to increase the capacity of the pumps, the

original prime mover must be ordered of sufficient size to cope with the increased duty. If much rise in throughput is effected, the rise in power required is considerable, and at the same time the working pressure will rise, unless additional capacity to the main lines is added. It must be remembered that for any given system of pipelines, the power required varies as the cube of the throughput, assuming no difference in elevations between stations.

With centrifugal pumps some similar flexibility can often be obtained at a future date by change of impellers. This similarly calls for the initial installation of large size prime movers.

accounting for an apparently bad volumetric efficiency of the pump. Is this due to a faulty pump, or a leaking relief valve, or the constant lifting of the relief valve? This problem with relief valves has induced many engineers to place them, not on a by-pass to the suction side of the pump, but on a direct line to station tankage, thus making it far easier to diagnose the cause of apparent volumetric inefficiency.

It is possible for the kicks of the pump plungers to set up pressure waves in the oil lines that may be reflected back from a tee or other manifold fitting to return to the pump in synchronism with the next wave, i.e. for the pump strokes to be in synchronism with the natural periodicity of the

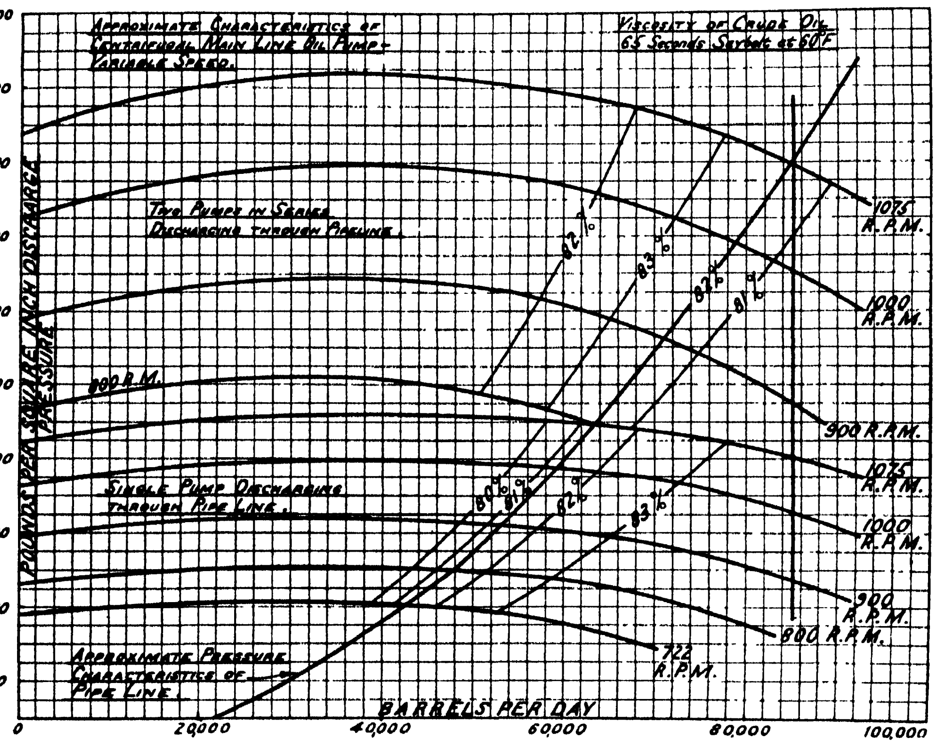

FIG. 1.

The reciprocating pump requires a device on the discharge side to flatten out the kicks of the pump. This corresponds to the high-pressure air vessel often found on the discharge side of water-pumping systems. However, such a simple device cannot often be applied to oil, not only because of a lack of the necessary air or gas in the oil at high pressure to charge the vessel, but also with some types of oil to their ability actually to dissolve and thus remove air from an air vessel. Hence some devices have been made incorporating a plunger between the free oil surface and the cushion of air above it, others depending on the working of a spring rather than the compression of air to obtain elasticity. Such air devices call for the provision of high-pressure air compressors for keeping the chambers charged; and precautions are required to ensure that when these chambers in turn have to be emptied of their air, this may be discharged into the open air, otherwise there is a danger of putting quite a large quantity of highly explosive mixture into the pump room.

The high possible closed-in pressures built up by reciprocating pumps call for relief valves by-passing to the suction side of the pumps. Now relief valves may operate noiselessly or may leak, so that the problem may arise of

piping system. This is not probable, but it has happened with consequently high and dangerous peaks of pressure waves, and, therefore, the natural periodicity of the pipe system leading from the pumps should be checked against the pump speeds.

Large reciprocating pumps are not an ideal load for an electric motor, although this form of drive is sometimes installed. If the pumps are large an appreciable ratio of step-down gear is required, and the inherent cyclic torque variation of the pump is apt to give an awkward and noisy drive. This latter disadvantage is not so apparent with triplex pumps as with duplex, the torque curve of the triplex pump being much smoother than that of the duplex pump.

In addition to better torque requirements the triplex pump in large sizes has certain other advantages. For a given capacity its overall length is less, thus cutting down the waste of space in the engine room. It is also less bulky and less heavy to install. Its use is common for throughputs exceeding 20,000 barrels per day per pump. The greater the throughput, the commoner is the use of a triplex instead of a duplex pump.

Centrifugal pumps can operate directly connected 'fore and aft' to the pumps at the next stations. In fact, for

reasons to be explained later, this connexion is sometimes a distinct advantage in enabling a considerable positive pressure to be maintained on pump suctions. This eliminates the necessity for station tankage. Manifolds are simple and cheap, and the total area required for a station is small.

It may be pertinent at this point to remark on the speeds of centrifugal pumps. There are some marked advantages in raising the running speeds as high as practical. Efficiencies tend to be better, and the weight of units decreases. However, opinion is inclined to be conservative when step up gears are necessary. Ratios bigger than 6 to 1 are not yet popular. This confines the speeds of Diesel driven centrifugals to approximately 1,500 r.p.m. However, with turbine or motor drives, speeds of 3,000 r.p.m. and over are possible and are in use. Even so, there may be trouble at these high speeds due to the possibility of cavitation with quick loss of efficiency, or even serious damage to impellers. A high pressure on the suction side of the pump undoubtedly lessens this tendency to cavitation, but much depends on the impeller design of individual pumps. High pressures on the suction side are uneconomical in that they reduce the possible distances between stations with any given piping system. Further data obtained after long periods of operation must be awaited before safe limits to pump speeds can become accepted or standardized.

Choice of Driving Units

Steam.

The next most important point is the type of driving unit to be used. The prime source of power may be steam, Diesel, or electrical. Steam has the disadvantage that first cost and the cost of maintenance may both be very high. However, there are notable instances where steam was installed in the past, maybe when there was no other choice available, and where such installations have grown with steam power and grown very efficiently. Probably the most notable is one which was in advance of its time when turbo-driven centrifugals were installed in 1919–20.

It has a unique position in that it lies parallel and close to a river that throughout the year gives an ample supply of water. Its size has warranted the expense of highly skilled supervision of water treatment, and, the usual bugbear of a steam station, incessant boiler maintenance, has thus been cut to a minimum through the very high efficiency of the water treatment carried out. Boilers now steam for 6,000 consecutive hours. Steam turbines and centrifugal pumps obviously offer a most attractive proposition in such site circumstances where the shaft horse-power in continual operation reaches a high figure.

For lines of large throughput the rise of the centrifugal pumps may well see a return to steam power with the use of turbines. It is unlikely, however, that there will be much further demand for steam reciprocating engines. Their place has been taken by Diesels.

Diesels.

Diesel engines outside the U.S.A. are probably the most common form of prime mover now being installed. They have been developed for running on crude oil as their fuel, thus often living on the main pipeline without the necessity for carriage of special fuels. Their main disadvantages lie in their high first cost, their heavy foundations, their auxiliaries, the careful maintenance required, and the expense of moving them from one site to another. Modern gears permit of reduction in speed between the Diesel and its reciprocating pump, or an increase of speed to its centrifugal pump.

They are also being used with electrical gearing connecting them with their pumps. As an example of one of the many possible arrangements there is a layout consisting of three Diesels driving three A.C. generators, each with an exciting unit on the same shaft, and current from these alternators is taken to two squirrel-cage motors driving two centrifugal pumps. The exciters are of sufficient capacity so that any one can provide the exciting current for all three alternators, or it can supply enough electrical power for all auxiliaries and domestic lighting at the station. There are also interesting devices installed for ensuring ease of paralleling the generators. It will be seen that by varying the speed of the generators the periodicity of supply is varied, and consequently the speed of the motors and pumps. Precautions have been taken to ensure that the heavy starting current required on the second squirrel-cage

TABLE I

Comparative Efficiency of Centrifugal Pumps operating at Reduced Speed v. Throttled Discharge Valve

	No. 1	*No. 2*	*No. 3*	*No. 4*	*No. 5*	*No. 6*	*No. 7*
Test run:							
Gen. Frequency	60	60	60	55	55	60	50
No. of engines operating	3	3	2	3	2	2	2
Rate bbl. per 24 hr.	42,100	37,489	37,578	37,486	37,466	34,567	34,616
Suc. pressure	120	15	15	15	15	15	20
Dis. pressure	767	720	720	595	595	720	460
Line pressure	767	595	595	595	595	495	490
Hydraulic h.p.	465	368	369	368	369	280	277
Hydraulic kw.	349	274	276	275	274	209	205
Combined eff. motor and pump	76·3	61·9	61·4	75·6	75·6	49	74·8
Motor eff.	92·4	92·2	92·2	90·7	90·7	92	90·9
Pump eff.	85	67·1	66·6	83·4	83·4	53·3	82·3
A.C. volts	2,300	2,300	2,300	2,200	2,200	2,300	2,100
K.W. per hour	530	442·9	448·8	363	363	427	274
Motor speed	3,560	3,565	3,565	3,270	3,270	3,560	2,969
Motor amps.	132	127	129	110	110	123	92
Engine Speed	400	400	400	365	365	400	333
H.P. output engines	695	668	654	654	546	632	430
Brake M.E.P.	49·2	47·3	69·2	43·7	63·4	65·8	54·5
Lb. fuel per B.H.P.	0·432	0·458	0·434	0·460	0·412	0·432	0·417
Lb. fuel per kw.hr.	0·580	0·690	0·632	0·712	0·616	0·638	0·655
Lb. fuel per bbl. oil pumped	0·173	0·196	0·181	0·166	0·144	0·189	0·125
Kw.hr. per bbl. oil pumped	0·302	0·281	0·287	0·233	0·233	0·298	0·190

motor to be started shall not be beyond the capacities of two of the generators running in parallel. Such a combination is interesting and offers great possibilities in flexibility. Although the overall efficiency must be less than the efficiency of a set of gears between the Diesels and the pumps, this disadvantage is probably more than balanced by the flexibility obtained, the power at all times to work the Diesels near their full load, and the ability to vary throughput without resort to hand throttling. Although it might be supposed that with centrifugal pumps throttling would not lead to great loss of efficiency, it has in practice been found to do so. Table I [1] shows the result of some interesting trial runs made on this layout.

Electricity.

There are many stations where it is possible to buy electrical power, and where this is possible this form of power is always worthy of consideration. The form of load with its 100% lead factor is one very favoured by power companies, and consequently power that can be obtained from an outside supply company is usually on as low a tariff as is given to any consumer. In this connexion it is interesting to note that in the U.S.A. the use of electricity for pumping-station work has increased rapidly during the last few years. It is stated that in 1931 20% of the horse-power installed on pipelines was electrical, whereas this figure had increased to 80% in 1933 [2].

Electric motors offer great variety and flexibility of drives. They can be geared down for reciprocating pumps and they can be direct connected to centrifugal pumps. Installation costs are small, concrete work is a minimum, and expense and time in moving if required from one site to another are low. Electrical power combined with centrifugal pumps has further possibilities. Pump stations can be made automatic. The pumping industry has, in fact, been very slow to take advantage of the possibilities of automatic control, far slower for example than has been the electrical distribution industry.

Electric motors driving centrifugal pumps manifolded across non-turn valves on the main line can be made to start up by a rise in pressure in the main line in conjunction with a float switch. The necessity for this float switch is that with any fluid, but particularly with gassy fluid, pressure may be built up at a station when pumps are started up the line long before the fluid actually arrives at that station. The float switch is so arranged that unless fluid is present it is impossible for the main starting apparatus to operate, or alternatively, if the supply of fluid to the pumps fails the pump motors will be shut down. It thus prevents the possibility of the pumps being started by the gas pressure in the main line or running dry. The unit may also be protected by various relays to throw out the main power breakers in certain eventualities such as a sudden drop of pressure due to a burst line, the rise of temperature in any bearing, &c. It will be seen that the whole operation of motor and pump can be made automatic and self-contained.

Combined units, pump and motor, have been made with the main-line fluid cooling the casing of the driving motor and the lubricating oil of a forced feed lubrication system [3]. It is claimed for such units that they may be brought up by lorry and placed in the main line without any foundation work, and be operating within 24 hours. This factor has led to savings in installed machinery, as where otherwise stations would each have needed standby sets of motors and pumps, one spare unit carried in a central store can cover standby requirements for several stations. Although such combined units are expensive in themselves, the total cost of such a station is low—no buildings, no auxiliaries, no tankage, and a very small total station area.

A further possible application to main line pumping is that of remote control. By it one oil movement office could control the whole of a big pipeline system. Modern remote control gear makes possible the starting or stopping of any pump, the opening or closing of any valve, and the reading of any instrument, all by one oil movement office. However, the next step in this line of theory has a practical flaw. Theoretically one central power station could provide power for the whole of a system, practically the cost of the transmission lines and their charging currents rules this out of economical consideration.

Where electricity is used to drive main-line pumps, it is customary to take some advantage of the possibilities offered of speed variation. This can be obtained theoretically in many ways, e.g.:

(1) Wound rotor slip-ring induction motors,
(2) Motor generators with d.c. motors to drive pumps,
(3) Scherbius control system.

Of these three systems the theoretical advantages possible with the first are the least, but the costs of the remaining two are such that as practical propositions they are ruled out for use except in very exceptional circumstances.

The wound rotor induction motor has a loss of efficiency when the speed is reduced by the insertion of resistances in the rotor windings if the torque is kept constant. But this is not of great importance with centrifugal pumps. The requirement for power of a centrifugal pump varies with the cube of the speed; hence on a drop of speed the reduced efficiency of the motor is to some extent balanced by the reduction in power required. The following figures give the approximate effect that may be expected, with drops in speed, of a centrifugal pump of about 40,000 barrels capacity:

% speed	*% throughput*	*% efficiency of pump*	*% of shaft h.p. required*
100	100	84	100
92	93	83·5	75
83	82	82	65

Pump- and Engine-room Design

With electrical drive it is possible to obtain flame-proof motors and starters and so combine in one room the prime mover and the pump. Even so, this is not universal practice. A firewall usually separates a pump from its electric motor, and always should separate a pump from its driving Diesel. This firewall brings with it a compulsorily long shaft and consequent difficulties in alinement. The installation of one or two flexible couplings is common practice. If one flexible coupling is used this can be installed on the side of the firewall remote from the pump. There is then a shaft between it and the pump which passes the firewall by a gland incorporating a soft packing easy to tighten up without over-tightening, and thus also easy to maintain gas proof. On the other hand, a single coupling does not allow of very much misalinement; in fact theoretically it calls for the meeting in one point of the two parts of the drive each perfectly alined, and often in practice heavy stresses are unexpectedly thrown on bearings. If of a correct type it does achieve freedom of end float which is vitally necessary for temperature changes and freedom from gear trouble.

Its use can be compared with expecting a motor-car to run satisfactorily with one universal joint and not two between its engine and its differential.

The installation in the drive between the prime mover and the pump of two flexible couplings and an intervening jack shaft allows more flexibility in alinement. Theoretically it is perfect, but the firewall gland is more difficult.

The couplings themselves may be either of the torsionally dead type or have springs to permit of torsional flexibility. Both types are in common use. With all drives it is necessary when designing to watch carefully the possibility of trouble in the future due to torsional vibration of the main drive system as a whole. Many apparently inexplicable failures of crankshafts in the past have been due to running for long periods near critical speeds of the shafting system, and there are many drives in existence to-day that so far have been successful but that are undoubtedly going to fail in the course of time. The connexion between a Diesel engine and its pump is notably one on which torsional vibration is likely to give trouble, but it is quite possible even with electric motors driving centrifugal pumps to obtain similar trouble, and these drives also ought to be checked. Where it is found that torsional vibration is likely to cause trouble, the flexible coupling may offer a good point where appropriate correction can be made by the insertion of springs with elasticity in torque. The natural periods of the drive may be taken out of the region of critical speeds, or when critical speeds are approached the extra stress on the springs thus added may alter the effective length of the springs, and thus also their mean effective shaft length, so that the critical speed of the shaft system as a whole may be removed from that running speed.

The Diesel engines installed in the past in main-line pumping stations have been of the slow speed type, and, depending on size, the range of 200 r.p.m. to 400 r.p.m. covers the vast majority. However, Diesel engine design is progressing and their speeds are increasing so that it may be expected that speeds of main-line pumping station Diesel engines will, in the future, tend to rise. Engine weights will be cut down with a consequent decrease in the cost of engine, cost of foundations, cost of installations, and cost of removals.

It is easy to step down from the r.p.m. of Diesels to the slow speed of reciprocating pumps by single reduction gears which are invariably incorporated with the pump itself. It is also becoming possible with modern gear making to gear up to centrifugals of moderate speed. Heavy fly-wheels, or increased numbers of cylinders, are required to reduce the cyclic speed variations to below 1 in 200 for such a combination.

With the arrangement of a Diesel engine driving a reciprocating pump, the length of the pump itself means that there is ample room between the Diesel engines in the engine-room, and attention must be paid to the pump-room side of the layout to ensure that in the event of a break-down of the pump there is the necessary room available for repair work, permitting the withdrawal of the side rods, &c., without the shutting down of further units. With centrifugal pumps, on the other hand, there may be a tendency to save space, but unless ground and buildings are very expensive great saving of space is not usually justifiable. If an engine is to be taken down, it is necessary that there should be no interference with adjoining units, and that the repair gang on a stripped engine should have ample room to work.

The Diesel engine is governed on the fuel system, and engines can be obtained with a running range from 65% to 110%, or more, of their normal running speed, with governors that can be set to maintain any speed in the intervening range. However, there is a peculiarity in pump-station design that does not arise in many other forms of Diesel engine uses. It is possible in the event of a leak of the fluid being pumped for gas to enter the main air inlet to the engine and race the engine, with the governor operating quite fruitlessly on the normal fuel injection system. For this reason the air inlet to Diesel engines should always be in the open air outside the engine-room and well away from the main pumps.

Many pipelines are so sited that there is a big range of difference between maximum summer temperature and minimum winter temperature, thus calling for some provision to be made for heating the engine-room in the winter. With steam prime movers this is a simple problem. It can also be handled with economy in Diesel engine installations by the provision of exhaust heat boilers. These can be placed outside the engine-room, and may either be of the type that will act also as a silencer when steam is not required, or may be of the wet type with two-way valves arranged between them and their Diesel engines, permitting the exhaust gases to be by-passed through a separate silencer when steam is not required. Care must be taken to see that even when the engine is on low loads the temperature of the gas leaving the boiler is not brought down to a point where sulphuric acid will deposit, with consequent necessity for early replacement of stacks and boilers.

It has been said above that Diesel engines can now be obtained that will run on most crude oils. This is true, but the fact also has to be faced that on certain types of crude Diesel engine maintenance is much heavier than when they are run on proper fuel—liners, journals, atomizers, exhaust valves and their seats, and the lubricating oil all suffer.

The running costs of Diesel engines largely depend on the treatment of the lubricating oil. In the past, batch centrifuging of lubricating oils heated by outside sources, such as steam available from exhaust boilers or electric immersion heaters, has been the normal form of treatment. The complete withdrawal for cleaning of all oil and its replacement by cleaned oil can be done without taking load off the engine. Records show that when attention and care is taken with the treatment of lubricating oil, the cost of such treatment is more than regained by the resulting lower consumption of oil and lower maintenance costs of the engines. However, there is a tendency now for stream-line filters to be installed on a perpetual by-pass across the lubricating pumps of the Diesel engines or to be added after the centrifuge on the batch system. Everything points to this form of treatment proving highly efficient.

For the same reason that steam-driven sets have so often been replaced by Diesel engines, i.e. the expense and badness of water, the cooling system of Diesel engines needs considerable attention. The present tendency is for the cooling water system to be a closed circuit cutting down the make-up water required. This can well be cut to a figure approaching 10 gallons per day per engine. Where exhaust boilers are installed the make-up water can be obtained by distillation. Where exhaust boilers are not installed unless the local water is of exceptional quality, treatment of the make-up water is economically advisable. The circulating water pumps, instead of being an integral part of the Diesel engine in such a system, are separate units. Standby circulating water pumps are very necessary, as failure shuts down the station. Where the circulating water pumps are driven by electric

motors, standbys driven by small Diesel engines have been installed. Warning devices can be placed to ring alarms in the event of failure of water pressure, or if the jacket of any engine commences to get hot. In such a system the outlet temperature from the engines can be kept constant and a high rate of flow maintained through all engines, regardless of their speed or load. Furthermore, on shutting down an engine after its period of duty, circulation can be maintained until it has cooled down throughout at an even rate without sudden excess temperatures arising in hot spots on cessation of water flow. A diagram of such a system is shown (Fig. 2). The water in the system may be cooled by passing through a heat exchanger, the other liquid in which may be water in turn cooled by evaporation or other means, or it may be the fluid in the main line, and this latter is a practice that is becoming almost standard. Heat exchangers are placed in the main pump section or discharge lines and the circulating water passes through these. The discharge side has the advantage with the high pressure available that the heat exchanger can be made small with high velocities: the consequent drop in head on the discharge side of the pump apparently is not objected to although, of course, this drop in head is equivalent to the friction loss of a certain length of pipe in the main lines, so that the maximum distance between stations is correspondingly reduced. On the other hand, the heat exchanger has to be made to withstand considerable pressures, and the differential pressure between the oil and the water side is such that a leak between the two will mean oil passing immediately into the cooling water system. If the heat exchanger is placed on the suction side of the pump, the head available for the main line fluid is usually so low that velocities through the exchanger have to be low and consequently its size is large and the cost is high. Furthermore, care has to be taken to ensure that the heating does not, in the case of gassy fluids, cause gas to come out of solution. Care also has to be taken if gas is formed in

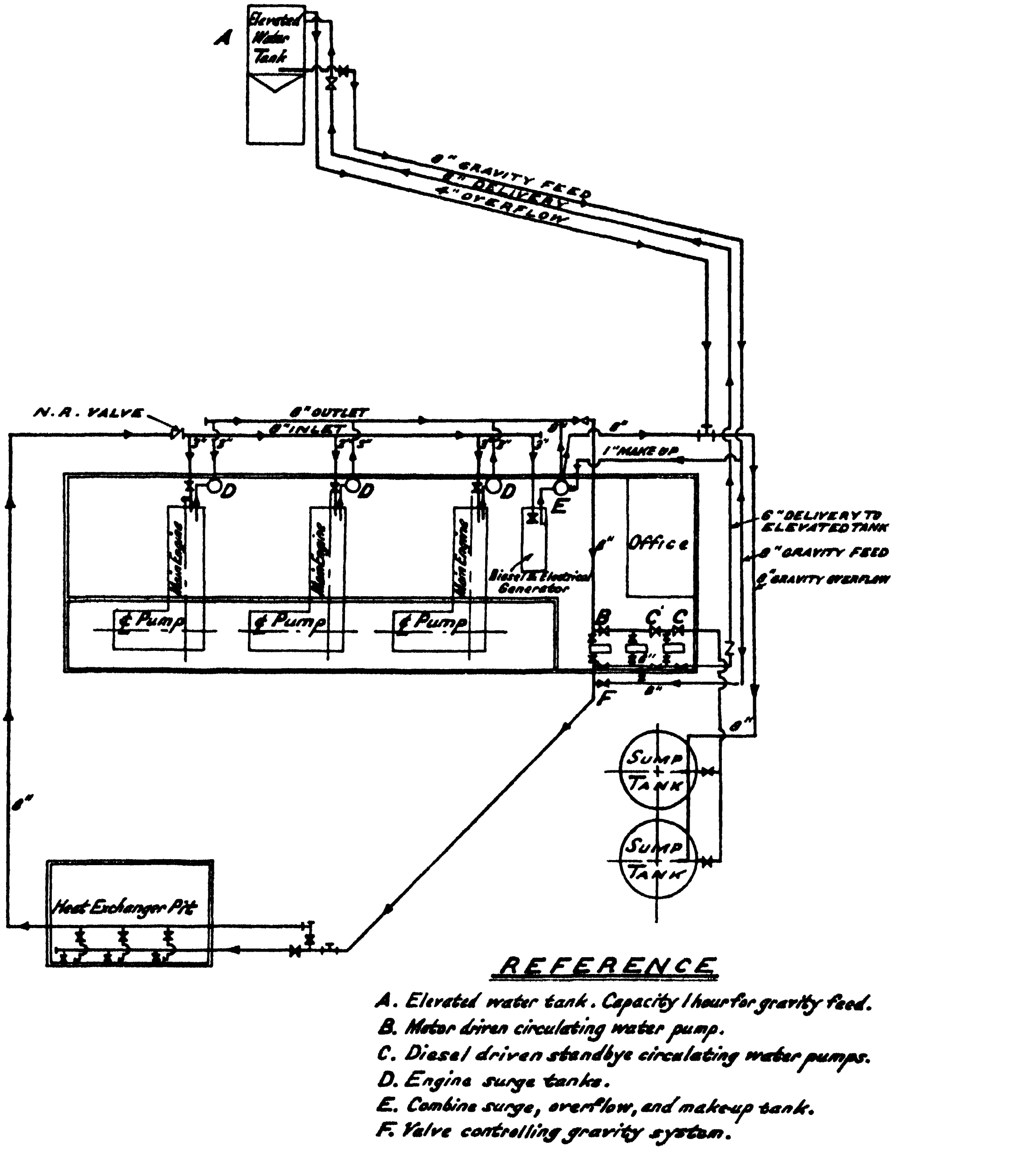

FIG. 2.

the heat exchanger to see that no gas can collect in any quantity. For this reason if heat exchangers are on the suction side they should be placed low with a steady rise to the pumps, so that gas if formed will tend to pass up to the pump and there be again compressed into the oil.

Station Electrical Supply

Where Diesel stations are installed it is frequently necessary to house station staff. This in turn calls for a supply of electricity for the housing as well as for the main station lights and auxiliaries, and in these days it is often desirable that such housing should be electrified to the extent of the installation of electric cookers, hot water heating, and other domestic appliances, forming in all a load that will be appreciable in size. The station itself will have electrically driven auxiliaries in the form of circulating water pumps, service water pumps, fire pumps, suction and sump pumps, compressors, &c. The question then arises as to how it is most convenient to supply the necessary electrical power. The possible alternatives are to connect generators by belt to the main engine drives, or to install separate generators driven by their own Diesel engines. If generators are driven off the main engine shafts and a.c. is used, it will be difficult, if not quite impractical, to parallel two or more generators. Hence the switchboard becomes complicated with throw-over switches to ensure that any load can be thrown on to any generator, but on to only one generator at a time. When the power required is small in amount this can be arranged without an unduly cumbersome switchboard. When, on the other hand, the power and number of feeder circuits required are large, this switchboard arrangement becomes impractical. Furthermore, as the size of generators becomes larger their addition to the main engine load has an appreciable effect on the cost of the station as a whole. The requirements of the generator may be an awkward varying addition to the power required from the Diesel engine, and its installation may lengthen the shaft between the Diesel engine and pump which, besides being in itself undesirable, may also add several feet to the width of a long engine-room, and thus add considerably to the cost of the building.

The trouble in paralleling engine-driven generators may be overcome by the use of d.c. Compound wound generators can be obtained with adjusting resistances that can be thrown in for particular speeds of rotation that will permit of generators being run in parallel, although their various speeds differ considerably. However, the size of generator becomes large and unwieldy and the type necessary is expensive. It is doubtful in fact whether this form of power supply is ever justifiable. Once the size of the generators required much exceeds 5% of the capacity of the main engines, it will be found simpler and cheaper to install separate generators each with its own Diesel engine. With modern Diesel engines the fact that a station with three main engines has in addition two small engines is of little consequence. Such a system has the further advantage that before the main line can start full operation, or in the event of a shut down, voluntary or involuntary, of the main units, full electrical power is available for all auxiliaries and the amenities of the station staff.

Manifolds and Layout of Station Areas

Another improvement available from modern methods of manufacturing is that of pipe bends, now available in all practical sizes in the form of forgings having a constant wall thickness. This, together with modern welding, has had a perceptible influence in the design of manifolding. Quite complicated manifold fittings may be built up in shops of pipes, bends, and flanges. Such fittings are lighter to transport, safer, have more spring, and are easier to repair or alter in the field than any of the old-fashioned cast steel fittings, besides having fewer flanged joints to be maintained.

Manifolds are usually sunk to the level of the buried main line passing into and from them. The installation of a concrete pit to contain the manifold is usually justified. Once successful operation has commenced the pit can be backfilled with shingle as a mechanical protection against damage, and as an insulation against temperature changes; or at very little expense a manifold pit can be roofed, with overhead runways installed for chain blocks thus permitting very easy and quick repairs, alterations, or additions.

In the design of manifolds and their connexions to pumps, especially where heat exchangers are incorporated, precautions must be taken against possible Thermo-Piezo effects. The coefficient of expansion of oil is considerably higher than that of steel and, therefore, where manifolding, piping, or heat exchangers are exposed to possible variations of temperature in any lengths between dead tight valves, excessive pressures may build up. With the ordinary variations of atmospheric and sun temperatures throughout the 24 hours, these pressures can build up to figures of 1,000 or 2,000 lb. per sq. in., and, therefore, particularly where heat exchangers on the suction side of pumps are incorporated, it is necessary to fit reliefs; or it is sometimes possible to insert small by-passes across valves to prevent dangerous pressures building up which may damage the equipment.

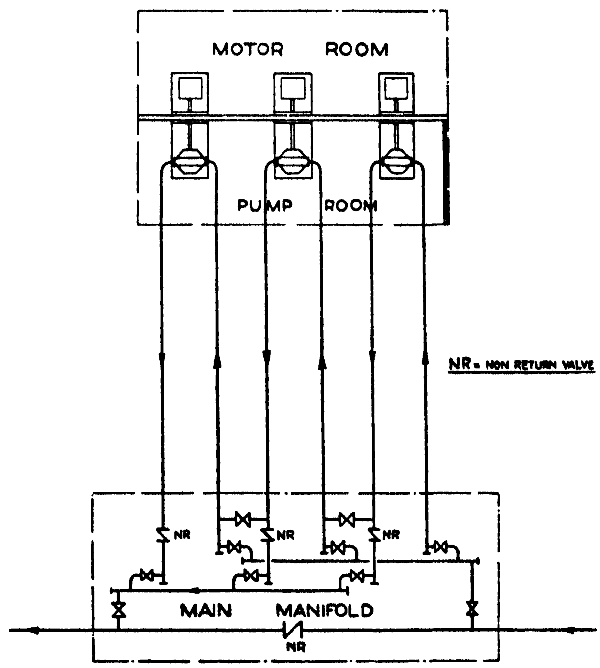

FIG. 3. Typical layout for motor-centrifugal pump station.

The choice between reciprocating pumps and centrifugal pumps has an effect in a marked difference of the general layout of the station plot. With reciprocating pumps it is necessary at least to carry what amounts to a balancing tank on the suction side floating on the line. This tank is usually of a capacity sufficient, not only to take up the difference between station rates of pumping, but also to allow a good time lag for stations fore and aft to continue

pumping in the event of any station having an involuntary shut down. For many oils unless these tanks have floating roofs, which are expensive, the evaporation losses at stations may accumulate to a figure worthy of consideration. The tanks themselves, and the pipes and fittings leading to and from them, are expensive. The area which such a tank calls for may also be an expensive item. These disadvantages need not be considered when the layout of the line is such that measurement by tank dipping is necessary at a station, and thus working must be by 'fill and draw'.

Centrifugal pumps, on the other hand, will function from pump to pump without any intervening tankage. They may, in fact, be connected across the main line with a non-return valve by-passing them, so that no damage will result if a pump shuts down. The flexibility of the use of such a device can be seen in Fig. 3, showing three pumps so coupled across a main line. The combinations possible with such a coupling are—no pumps in operation, one pump in operation, two pumps in operation or parallel, or two pumps in operation in series, with one pump at least always acting as a standby. The manifolding is simple, cheap, and foolproof. It is almost impossible for ignorance to so manipulate the valves that dangerous pressures can occur.

Dust Proofing

Pump stations happen frequently to be sited where dust storms are prevalent, and this has led to provision of dust proofing to a greater extent than with most industries. For example, Diesel engines and reciprocating pumps have been supplied in the last few years totally enclosed by dust proof covers. With reciprocating pumps certain difficulties have to be overcome due to the fact that inevitable gland leakage of a gassy crude would cause the formation of a highly explosive mixture beneath the dust covers. To guard against this a ventilating system has been devised depending for its action on the displacement of the pump plungers. Air is drawn in through dust filters and in turn expelled through light non-return valves placed close to the plungers and also handling their leakage. From the non-return valves the expelled gases are piped outside the pump room to atmosphere in the open. Besides expelling possible explosive mixtures, this system has the advantage of constantly moving air through the dust covers, thus cooling the working parts.

With electrical machines dust filters are often fitted on the inlet of pipe ventilated machines. Where big motors are used, their venting is frequently made through their base and beneath the floor of the motor-room to the open air.

The air inlets to all Diesel engines, as has been mentioned elsewhere, are taken from the outside of the engine-room, and these again are protected by air filters.

A type of air filter that has proved very successful is a dry gauze and felt type with a very large area for passage of air. These, provided that the dusty atmosphere is not oil laden, have proved easy to clean. On small units tapping will knock off loose dust, which will not build up. The surface being vertical, almost all dust falls off them without any attention especially where there is any vibration. On big units attachments are fitted whereby compressed air can be blown in jets backwards through the filter.

Fire Protection

Fire protection of stations needs consideration. In practice the basic idea is usually to provide handy equipment for very quick application in the case of fire, but rarely is any attempt made to provide equipment of sufficient capacity to put out any really large fire. To do this the equipment would be of such a cost that it would not be justifiable at all stations. Third-party and consequential risks may in particular instances call for such equipment.

Hand chemical extinguishers are provided of a type suitable for putting out incipient fires in electrical machinery, and hand chemical extinguishers are further provided suitable for prompt application to incipient oil fires.

Frequently, in addition, portable hopper type foam-making equipment is supplied for attachment to water hydrants. This necessitates a high-pressure water system being available, and in some sites this in itself is expensive and difficult to provide.

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THE TRANSPORT OF OIL BY RAIL AND ROAD

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BRITISH ISLES

ORIGINALLY country depots received their supplies from the ocean-fed installations by rail car, but within recent years the use of road transport and (where practicable) water transport have been developed. The introduction of pneumatic tyres and the increasing use of Diesel-engined vehicles have brought about reductions in road costs, and it is a general principle that the oil companies only utilize rail transport when they cannot do the business by road or water transport at a lower cost.

Rail-car Transport

In 1928 the railway companies issued a new classification applicable to goods traffic, goods being chargeable under 21 different headings varying from 1 to 21, the lower the number the lower the rate charged. The following examples will indicate how the rates vary:

			Classi-fication.
Fuel oil in owners' tank wagons			7
Kerosine „ „ „			10
Motor spirit	„ „	(12 tons)	13
Motor spirit	„ „	(8 tons)	14
Fuel oil in barrels	(2-ton lots)		10
Kerosine „	(2-ton lots)		11
Motor spirit „	(3-ton lots)		15

The rates obviously vary according to the nature and value of the product carried, the lower flash products qualifying for the higher rates.

Where a depot is fed with motor spirit by rail-car it is obviously cheaper to use 12-ton cars rather than cars of smaller capacity, except in cases where the depot through-put is relatively low and the capacity of the storage tank is insufficient to accommodate the contents of a 12-ton car. In the case of kerosine there is not the same inducement to use cars of 8 tons (or over) capacity.

In Great Britain all rail cars used for petroleum products must comply with the regulations of the Railway Clearing House, and cylindrical tanks are usually employed. These are of various sizes, from 5 ft. 10½ in. diameter by 17 ft. 4 in. long up to 7 ft. 2 in. diameter by 21 ft. 5 in. long, with capacities varying from 2,700 to 6,000 gallons. In other countries much larger cars are in use, the 10,000-gallon car being common in the United States.

In Great Britain rail cars used for the conveyance of spirit must be painted a light stone colour and have to be provided with only a 'top outlet'. They have steel under-frames and oil-lubricated axle boxes. This type of car is often used also for kerosine traffic, since it is obviously an advantage to be able to divert rail cars from spirit traffic to kerosine traffic, or vice versa, according to seasonal demands. In winter the relative demand for motor spirit as compared with that for kerosine is less than it is during the summer, and if the surplus cars are 'top outlet' cars they can be diverted to kerosine traffic in the colder months without any difficulty. The oil companies pay a commuted charge of sixpence per wagon per year to cover the transfer of empty rail cars from one place to another, due to trade fluctuation.

Rail cars for carrying kerosine, fuel oil, lubricating oil, and bitumen may have either steel or wood under-frames and grease or oil axle boxes. Bottom outlet connexions are fitted, with a pipe and cock at each side for delivery of the product, and with an internal valve controlled by a spindle with a hand-wheel at the top of the rail car.

Fuel-oil cars are provided with internal pipe coils through which steam can be passed in order to facilitate discharge, this being necessary as a rule only with the heavy grades of fuel oil. Rail cars used for the transport of asphaltic bitumen and road oils are also fitted with internal coils and in addition are externally lagged so as to prevent undue loss of heat during transit. These bituminous products are loaded into the rail cars in a liquid state from heated storage tanks, and are delivered to the customer whilst still hot. The rail cars in this type of traffic are usually provided with connexions to enable them to be discharged by means of compressed air.

When loading spirit rail cars the rail track on which the car stands should be 'earthed' so as to prevent static electrical charges from being built up which might cause a spark and consequent explosion and fire. The rail cars are filled through the manhole up to the level of a bar (known as the loading bar) which is fixed a few inches below the bottom of the dome. By this means a 4% ullage is left, in accordance with the Railway Clearing House requirements, thus allowing for possible expansion of the contents of the car in hot weather. The gallonage of spirit in the car can be determined by one of two methods: (*a*) from the records, where the car is a 'gauged' car, i.e. its capacity to the loading bar has previously been determined; or (*b*) by weighing the car before and after loading, and noting the specific gravity of the spirit at the time of filling. If, for example, the specific gravity at the time of filling is 0·73, the gallonage is obtained by dividing the net weight in pounds by 7·3.

In many cases, especially in the fuel-oil trade, the rail cars are not 'gauged' and only the weight of the contents is determined, but it is necessary to calculate the gallonage also, since the hydrocarbon oils duty is payable on a gallonage basis.

Road Transport

During the last few years the road transport of petroleum products has expanded considerably, this being due mainly to the following reasons:

(1) The relatively high cost of rail transport.
(2) The comparatively short distances involved, and the increasing range of the modern pneumatic-tyred Scammell tank wagons.
(3) The very good condition of the majority of roads.

The standard unit for road transport between installations and depots is the 2,500-gallon capacity 5-compartment articulated Scammell tank wagon, this being the largest capacity vehicle allowed by law for the transportation of motor spirit. Prior to 1932 the limit for tank wagons within the County of London and the County Borough of West Ham was 2,000 gallons only, but these areas were

brought into line with the rest of the country by the Petroleum Spirit (Conveyance) Regulations, 1932, issued by the Home Office under powers granted in the Petroleum (Consolidation) Act of 1928. The large Scammell lorries are utilized considerably for 'Bridging' purposes, i.e. for feeding a group of local depots from a water-fed installation, but for delivery work generally at the smaller depots such vehicles are impracticable except for making very large deliveries to such customers as the London Passenger Transport Board or the Royal Air Force stations.

The system of distribution in the United Kingdom has gone very largely in the direction of many pumps and corresponding small throughputs, and this being a *fait accompli* it is too late in the day to alter the system. In consequence, the bulk delivery wagons at local depots may vary in capacity from, say, 300 gallons up to the maximum of 2,500 gallons, depending on the nature and volume of the gallonage involved. Naturally the larger vehicles are the more economical, and they are used wherever possible, the great point being to ensure that they are fully occupied and that dead mileage is cut down to a minimum.

The following are the more important provisions of the Petroleum Spirit (Conveyance) Regulations of 1932 as applicable to deliveries in tank wagons:

1. The engine, fuel tank, and electric batteries must be effectively screened from the body of the vehicle by a fire-resisting shield, carried up above the height of the load and down to within 12 in. of the ground. If the fuel used has a flash-point not below 150° F. (i.e. with Diesel-engined vehicles) the fuel tank can be placed behind the shield.

2. The exhaust must be wholly in front of the fire-resisting shield.

3. If of more than 600 gallons capacity, the tank must be divided into self-contained compartments, the capacity of each not to exceed 600 gallons (as already mentioned, the total capacity must not in any case exceed 2,500 gallons).

4. The filling pipes must be carried down nearly to the bottom of the tank in such a way that there is always a liquid seal at the bottom of the pipe, or alternatively, the covers over the filling opening must be provided with locks (in the County of London and in West Ham tank wagons exceeding 1,000 gallons capacity *must* have filling pipes with a liquid seal at the bottom).

5. Any openings in the dipping pipes, other than the upper orifice, must be covered with fine wire gauze of not less than 28 meshes to the inch, and any ventilating openings must similarly be covered with wire gauze of not less than 28-mesh.

Vehicles for road transport are loaded in a similar manner to rail cars except that where motor spirit is being loaded there must be a screwed connexion on top of the vehicle, this being attached to the hose fixed to the filling arm. Similarly, when a load of spirit is discharged into a customer's storage tank the delivery hose must be attached to the inlet pipe of the storage tank by means of a screwed connexion. During the filling operation the engine of the vehicle must be stopped, and adequate provision made, by means of some type of 'earthing' device, to prevent the accumulation of static electrical charges.

The gallonages delivered to a road wagon, or from a road wagon to a customer's tank, are arrived at by means of dip rods calibrated in gallons, each vehicle having its own rod for each of its tanks. It is one of the oil companies' conditions of supply that only the readings of their own dip rods will be recognized.

Storage Licences for Petroleum Spirit

In 1928 the whole of the petroleum legislation was consolidated in the Petroleum (Consolidation) Act, 1928, and all previously existing Acts were repealed. Petroleum spirit only is subject to the provisions of the Act, and there is no general legislative control over petroleum products with flash-points of 73° F. and over, with the exception that the London County Council possesses certain powers under its General Powers Act of 1912.

Under the 1928 Act the local authority is empowered to grant licences for the storage of petroleum spirit, and if it refuses to grant a licence it must state its reasons in writing if so required. The applicant, if still dissatisfied, can appeal to the Secretary of State, who may, after inquiry, grant a licence or modify the conditions sought to be imposed by the local authority. Under the old Acts a fee not exceeding five shillings was charged for each licence, but there is now a graduated scale, varying from 5*s*. per annum, when the quantity does not exceed 100 gallons, to £5, where the quantity exceeds 50,000 gallons.

Petrol Pumps

The petrol pumps used for retailing petrol to the public are measuring instruments subject to inspection by the inspectors of Weights and Measures, by whom they are stamped or sealed when passed as satisfactory. It should be noted that meters fitted to petrol-measuring instruments require the approval of the Board of Trade under the Weights and Measures Act (Section 6), 1904, and under Regulation No. 19 of the Measuring Instruments (Liquid Fuel and Lubricating Oil) Regulations, 1929, all petrol-measuring instruments must have a quantity indicator recording deliveries up to 10 gallons.

There are three main types of pump:

1. The type in which the barrel of the pump is the measure. Perfect fitting of the piston in the barrel is essential.

2. The type which has a container at the top of the pump into which the petrol is pumped, subsequently being allowed to run down the delivery hose. This type of pump is sometimes known as the 'visible' type.

3. The modern electric pump, in which an electric motor is employed to deliver a continuous stream of petrol which is measured by a meter, the quantity being recorded by a moving pointer on a dial. The hose is taken from the hook on which it normally rests, and a switch is operated so as to start the motor and the pump. The hose is fitted with a trigger valve which allows petrol to pass when it is opened, and in the interval between starting the motor and opening the trigger valve the petrol is circulated by the motor and pump through a by-pass, the by-pass valve closing automatically when the trigger valve is opened.

Bulk Distribution of Products other than Motor Spirit

The remarks already made have been applicable in particular to bulk deliveries of motor spirit, somewhat different problems arising in the distribution of the other products.

Although a large proportion of the kerosine trade is done in bulk, the quantities involved at a time are usually very much less than the average bulk load of motor spirit, and delivery must usually be effected in much more out-of-the-way places. Unlike the motor-spirit trade, where a bulk delivery cannot be less than 200 gallons at a time, deliveries of kerosine in minimum lots of 20 gallons qualify for the 'bulk price'. The oil companies have recently (January

1937), however, attempted to encourage deliveries in lots of 200 gallons and over by allowing a halfpenny reduction in price when deliveries of this size are taken 'through the hose'.

In the case of lubricating oil, bulk deliveries are made in the larger towns, where a special bulk lorry can be justified, but the motor-oils cabinets at garages are usually replenished from 5-gallon churns, the churns being refilled at the local depots and carried on the motor-spirit lorries.

Fuel oils of various types are normally delivered from installations or sub-installations by barge, rail car, or road wagon, and such products are, as a rule, not stocked in bulk at local depots. In certain instances supplies are forwarded by rail car to some convenient rail-head and are delivered locally to the customer by road wagon.

UNITED STATES OF AMERICA

Since the early days of the oil industry, crude oil has been generally transported by pipelines or tank vessels to refineries, but the methods of transporting the various refined products have undergone various changes since those days. As was formerly the case in this country, outlying depots in America received most of their supplies from ocean installations and refineries by rail-car. Within the past few years, however, there has been an increasing volume supplied by road, water, and also pipeline; this applies particularly to petrol. These developments were encouraged by the relatively high freight rates that prevailed for rail-car transportation. However, in the past 2 or 3 years there has been an increasing tendency on the part of the railway companies to reduce rates principally in competition with road transportation, and this, together with increasing restrictions upon transport lorries by limiting maximum weight, by increases in taxes, &c., has shown signs of reducing the rate of change-over in method of transportation from rail to road. However, there is an ever-increasing volume of water-borne traffic, which has been encouraged by the recent programme of the Federal Government for improving channels in some of the larger rivers—the Mississippi, Ohio, Hudson, and others. Pipeline transportation of petrol is generally confined to supplying markets where there is a highly concentrated demand, in inland cities, located at frequent intervals along the pipeline route. Thus petrol pipeline transportation is used on a large scale in the eastern part of the United States, whereas, generally speaking, the far western part is unable to supply the high concentration of volume.

Rail-car Transport

Rates. Rail rates in America are divided into two main groups: commodity rates such as petroleum, cotton, coal, &c., and class rates, based on a separation into classes of each article transported.

Rail rates are charged primarily on the distance which the freight is carried, the charge increasing with the distance; however, other factors must be considered, as the rail rate does not increase proportionately as the distance increases for the following reasons:

On every shipment certain services are performed, whether the shipment moves 10 miles or 1,000 miles. The billing of the freight and the issuing of the necessary papers, the switching of cars from point of loading, the making-up of cars into trains, the breaking-up at destination, collection services, overheads, &c., all represent charges that are approximately the same no matter what distance the shipment is moved. Therefore, as these charges are spread over actual cost of movement, the cost of carrying a ton of freight does not increase proportionately with the distance.

Furthermore, the rate structure varies with the locality, the density of traffic, the competition, and other factors. The oil industry's annual railway freight bill is in the neighbourhood of $250,000,000 (£50,000,000), which represents approximately 10% of the total freight revenue of the railways, and has been their largest single source of income.

Recent figures show that about 152,000 rail-cars are in service in America, of which 144,000 are owned by the oil companies and private rail-car concerns. Since the railways do not finance the construction or pay for the maintenance of these privately owned cars, they credit the owners' account with 1½ c., approximately ¾*d.*, per mile for each mile a car travels loaded or empty, provided it travels, over a period, the same number of miles both loaded and empty on the same railway. For all empty miles in excess of loaded miles on each railway, the railway companies charge the prevailing freight rate without making the above-mentioned credit allowance. The railways also make a charge for demurrage if cars are detained for more than 48 hours.

Description and Operation. In America rail-cars vary in size from 4,500 to 12,000 American gallons, with 8,000 or 10,000 gallons the size generally in use. Expressed in tons, these sizes are 12½ to 33½ tons and 22 to 28 tons respectively. They are built to rigid specifications laid down by the American Railway Association. These specifications cover details of the construction of the car, and failure to keep the car in proper mechanical condition results in the refusal by the railway company to accept it for movement. The manner in which cars are loaded and unloaded, together with precautions which must be taken in connexion with them, is carefully specified in regulations set up by the Government's Bureau of Explosives. Government inspectors are constantly investigating to ensure that their regulations are being followed.

Miscellaneous Uses. In addition to the more or less usual products transported, as mentioned above, there is an increasing amount of hydrocarbon gases transported by rail. These gases (butane and propane) are used for industrial purposes, for the enrichment of manufactured gas, and for the usual purposes by small communities which are located beyond gas mains. They are transported by rail-cars designed to keep them under a pressure sufficiently high to maintain them in their liquid state.

The foregoing only applies to the shipment of products in bulk. In addition, there is, of course, a very large volume of petroleum products carried in packages by the railways. This is transported in their own goods wagons, and in consequence a straight freight rate is charged with no deductions as in the case of products transported in bulk in a privately owned rail-car. Lubricating oil is one of the principal products transported in packages, in view of the fact that while the total volume sold is large, there is only a relatively small demand for one particular grade. However, it should be pointed out that the grades with the largest demands (some of the more generally used motor oils) are often transported in bulk by rail-car.

Road Transport

During the last few years road transport has expanded considerably, as mentioned previously, due in general to the same conditions as exist in this country, namely:

(1) Relatively high cost of rail transport.

(2) The increasingly good condition of the majority of roads.

(3) The improvements in lorry design, permitting the carriage of greater loads at higher speeds and at lower costs.

The usual unit in bulk service is the combination lorry and trailer type, which carries between 4,000 and 5,000 American gallons, approximately 12½ tons. Different states have different regulations regarding the maximum weight allowed and the conditions under which lorries must operate.

There are many transport lorries owned and operated by the large oil companies, but, supplementing this fleet, there is also a large number of privately owned units in general service.

These units are used for the transportation of all products other than lubricating oil, and supply large accounts such as service stations equipped with large storage tanks, commercial accounts using large quantities of products, as well as outlying depots. In this service an effort is made to keep the lorry operating day and night to reduce the capital cost of transportation to a minimum.

Lorries are also used increasingly to carry hydrocarbon gas in bulk in high-pressure tanks. In addition, they are also used to carry package goods to outlying depots. In both of these services, as well as in their usual services mentioned above, they are in direct competition with the railways.

The method of delivery from depot to ordinary customers is much the same in America as it is in England.

PRINCIPLES OF DESIGN AND OPERATION OF SEA TERMINALS

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THE principles of design and operation of sea terminals that will be dealt with herein refer particularly to crude-oil storage and may be taken as a standard for the erection of relatively small installations handling only finished products.

Transporation of crude petroleum and its many derivative products is one of the major divisions of the petroleum industry. By land and by sea, ceaseless streams of this precious commodity are ever flowing from the far-flung oilfields of the world to the busy centres of civilization. Underground the unseen pipelines and above ground long trains of railway tank cars move the crude oil from the oil-wells to either refineries or sea-coast terminals. Here the oil is accumulated, perhaps refined, and then continues its journey to the markets of the world via tank steamer, tank car, or tank truck.

The disparity between the location of the world oilfields and the location of the consuming centres (outside the U.S.A.) is such that practically all oil supplies at some stage of refinement must be transported by tankship. Tanker fleets, almost entirely owned by oil companies, comprise a substantial percentage of the world's merchant tonnage. At the end of the year 1933 there were about 13 million dead-weight tons of tanker capacity afloat, although only about 11 million tons were in operation. Of the total tonnage of foreign commerce of the United States in the year 1933, petroleum and its products comprised about 22 million short tons or about 37% of the total.

The operation of tanker fleets requires the establishment of suitable dispatching and receiving stations or terminals where the tankers may be loaded and unloaded. The functions of a terminal organization are to receive, store, possibly blend, and finally dispatch the oils for which it is designed. The terminal may consist of a very simple wharf, pump-house, and tanks for accumulating and discharging crude oil, or, on the other hand, may be a complicated organization handling all the products refined from crude oil.

Each terminal presents a somewhat different problem and it is beyond the scope of this article to go into detail regarding the many possible types. Only a general discussion will be given covering the salient points of design and operation of a modern terminal and its accompanying tank yard.

Principles of Design

The design of sea terminals is generally not a very difficult undertaking and consists mainly of the application of known modes of construction to the special conditions found at a seaport. In spite of this, the location and design of sea terminals should always be placed in the hands of competent engineers so that the owner may be assured of receiving a workmanlike job and that the terminal may be designed for greatest economy of operation and greatest adaptability to future changes. There is ample opportunity for the exercise of engineering ingenuity in designing a sea terminal for lowest capital and operating costs.

The major parts of an oil terminal are docking facilities, storage tanks, piping, and pumping equipment. In addition to these, and depending upon the location, whether near or far from modern civilization, the terminal may have to be provided with facilities for power production, water-supply, housing of the terminal personnel, communication facilities such as radio or telephone, and possibly others.

The engineer charged with the design of a sea terminal must know in advance the approximate quantity of the different products to be handled through the terminal and also be advised of any special handling or blending required. The rate at which tankers are to be loaded must be known so as to permit accurate selection of pumping equipment.

Physical properties of the various oils to be handled must be determined in advance so as to facilitate the design. This is important from the viewpoints of preventing corrosion when sour crude oils are to be handled, providing the proper sizes of lines to handle more or less viscous products, providing suitable heating for high pour-point oils, and the like.

The fact that practically all petroleum products are liquids at ordinary temperatures greatly simplifies the problem of handling materials, so that simple pumping equipment, or even gravity, is all that is required to move and transport material. Some products which are too viscous to be pumped economically at ordinary temperatures may be heated to reduce their viscosity so that they may be handled with the usual pumping equipment.

At many terminals petroleum products are handled in packages or barrels. The loading equipment used in these cases consists of conventional conveyor systems such as are used and well standardized in other industries, and will not be further discussed herein.

Petroleum coke in bulk may be loaded on ships or barges by means of an inclined belt conveyor discharging through a spout into the hold of the vessel.

The design of sea terminals will be discussed under the various subject-headings of Location, Docks, Storage Tanks, and Piping and Pumping Equipment.

Location.

Discussion of the location of sea terminals may be simplified by dividing them roughly into two functional classes; firstly, those engaged principally in making outward-bound shipments, and secondly, those whose primary function is to receive incoming shipments and then dispatch the products in smaller lots to inland redistribution points.

The first class is necessarily located as near as possible to the source of oil-supply and hence there is not much latitude in choice of location. The terminal must be located adjacent to deep water where ocean-going tankships may safely navigate. Oil is transported from the inland oilfields to the sea terminal by pipeline, shallow draught tankers or barges, or by railway. Often it is desirable to locate an oil refinery at the break-shipment point so

that transportation costs on the refinery processing losses may be saved. Thus it is quite common to find that terminals are operated in conjunction with a refinery, and any decision regarding the location of the one must be considered in relation to the other.

The second class, those terminals primarily engaged in receiving ocean shipments, are always located as near as possible to the consuming centres.

Aside from physiographical aspects, the choice of the actual site for either type is governed by the usual economic considerations in choosing industrial sites, although due to the inflammable nature of the products handled, local laws may play a large part in governing the actual location. For instance, in many of the large seaports a special area of the harbour is set aside for the handling of petroleum products so as to minimize the risk of a general conflagration. The physical configuration of the site plays an important part in the design of the terminal structures and should be considered in the final choice.

Docking Structures.

Choice of site for an ocean terminal may be influenced by the type of mooring or docking structure which can be constructed.

Structural requirements may vary roughly in accordance with the following, although modifications and combinations of these are commonly to be found:

1. Where no harbour is available, the construction of deep-water mooring buoys or stations, with underwater oil-lines from shore out to anchorage.
2. A pier extending from shore to channel, with provisions for mooring at end of pier.
3. A dock or wharf along shore fronting full channel depth.
4. A slip, or dredged-out indenture, permitting ship to enter at an angle to shore line and to moor at dock along one or both sides of the slip.

Fig. 1 shows four of the more common types of pile-driven docks. Type I is a section through an off-shore timber dock parallel to shore. Entrance to the dock is gained by means of a pier walkway extending out from shore, the whole being commonly termed a 'T-shaped dock'. Type II is a simple form of timber-constructed retaining-wall dock, fronting full channel depth. Type III illustrates the use of a 'relieving platform' of earth fill retained by a reinforced concrete wall in order to lessen total horizontal pressure on, and so reduce the length of, sheet piling employed. This type may be employed to economic advantage where the subsurface is particularly fluid and treacherous in nature, and where the terminal area available is to be extended out to the edge of the dock. Type IV is an example of the use of steel-sheet piling for the construction of a gravity type dock, or dock which will withstand horizontal thrust by virtue of its shape and weight. This type may be considered where the entire ground mass is extremely plastic in nature, and is underlain by a substantial foundation of hard-pan or bedrock.

The type of dock finally selected will depend upon a careful study of the topographical and geological features at the sites under consideration, together with a study of the natural forces affecting these features. A thorough study will necessitate:

(*a*) Determination by means of test borings, or geophysical instruments, or subsurface strata—down to bedrock if possible; samples to be obtained for laboratory or field testing.
(*b*) Soundings to obtain contour of channel bed, measurements of low and high tides, and elevation determinations of surrounding shore topography.
(*c*) Information regarding the magnitude of wind, wave, and tidal forces to be considered.
(*d*) Noting of the rate of deposition of sand and silt, with estimate of dredging required to maintain channel depth; observation of any bar- or spit-forming tendencies.
(*e*) Estimation of the extent and rate of future changes in shore line, due to erosion or deposition and study of means for prevention.
(*f*) Determination of the presence and activity of marine boring animals and soil insects.

Fundamentals of dock design may be resolved into the following:

(*a*) Determination of vertical loads and horizontal forces, with their distribution.
(*b*) Determination of depth to drive piling, spacing of piles, and location of points of anchorage.
(*c*) Determination of stresses in and selection of piling sections.
(*d*) Determination of stresses in and design of bracing, tie rods, and anchors.
(*e*) Design and tying-in of superstructure.
(*f*) Protection against impact from ships, waves, ice, or debris.
(*g*) Treatment of materials for preservation.

Piling in dock construction may commonly be subjected to forces of direct bearing, cross bending due to horizontal thrust or pull, or a combination of both.

The support of piling in direct bearing depends either upon the pile reaching bedrock or upon sufficient friction of the penetrated subsurface upon its sides. The extent to which this friction may be relied upon is seldom accurately predeterminable by ordinary bearing-pile formulae derived from test-pile loading results. Peculiarities of subsurface behaviour can be anticipated only through a study of sufficient test-hole samples together with the making of adequate laboratory tests of those samples.

Toe support of driven piling subjected to cross bending—or the preventing of movement at its base due to upper horizontal pressure of retained earth and superimposed loads—is provided by the resistance of the subsurface (*a*) to sliding laterally, (*b*) to rising against the force of gravity, and (*c*) to the breaking down of its cohesion. Tests to evaluate the angle of internal friction of the soil, its compressibility, elasticity, stability, and permeability are essential in order to predetermine this resistance with reasonable accuracy. Utilization of full strength of the surrounding ground mass is, of course, the theoretical ideal; however, the side of safety should never remain in doubt, and depth of driving should always be such that failure of the upper anchorage will not produce immediately dangerous consequences.

In Type IV, the width between bulkhead walls must be such that the structure will not overturn; sliding must be prevented either by its own weight or through sufficient pile penetration; walls must be tied together to maintain alinement.

Various forms of protection of the main structure against shock from berthing of ships and other causes are to be found. Pile clusters are frequently driven at regular

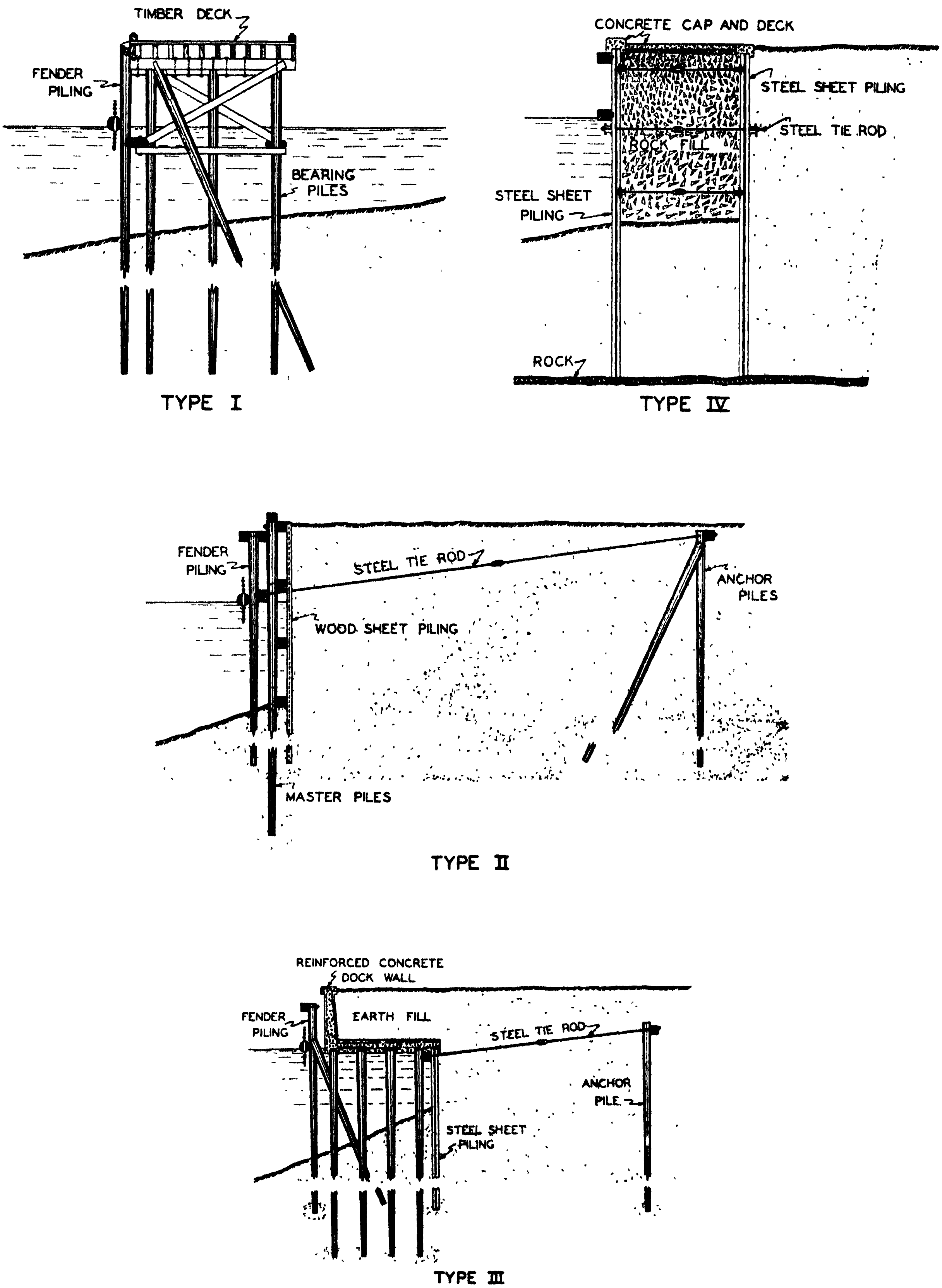

FIG. 1. Typical sections through pile-driven docks.

intervals in front of the main structure and opposite vulnerable points. Another form of protection is afforded by a row of 'fender' piling driven in front of the dock, the whole being fastened together and lined up with walling strips. In many cases it is possible to brace each fender pile with a batter pile, or pile driven at an angle and extending beneath the main structure. Impact from the ship is absorbed through the batter piles, and sufficient resiliency is present to bring the fender piling back to normal position after being struck. Another type employs a system of coil springs which permits movement of the batter piles independently of movement of the vertical fender piling.

Mooring-pile clusters are generally located at both ends of the dock, and additional mooring-pile anchorage is often provided farther ashore.

Regarding treatment of materials for preservation, space will permit but brief mention of a lengthy subject.

Timber requires preservation against three sources of attack: (1) fungi decay, (2) wood-destroying insects such as termites, and (3) marine animal borers, such as the teredo and the limnoria. Pressure treatment with coal-tar creosote has produced the most satisfactory product to date, it is believed, with the use of more heavily creosoted timber below mean tide level than above.

Concrete deteriorates in sea-water due to (1) mechanical abrasive action from wind, waves, ice, and debris; (2) chemical decomposition on both surface and along cracks formed through various agencies; and (3) rusting of exposed steel reinforcing with resultant expansion and excessive internal concrete stresses. Many attempts have been made with but varying success to introduce compounds into the concrete to check decomposition and form insoluble cement material. At present the most successful practice seems to be the vacuum-pressure process for impregnation of concrete piles with asphalt, and the use of various forms of asphalt surface protection for concrete superstructures. Membranes and coatings for such surface protection to be effective and long lasting should be impermeable to moisture, possess good ability to adhere to the surface, and be strongly resistant to weathering and abrasion.

Steel piling and steel superstructures above tide-level receive occasional coatings of paint or asphalt to retard the action of salt spray on the metal. Other than this, no further protection is commonly considered.

Storage Tanks.

Steel tanks are in almost universal present-day use for storage of oil, their construction and size being reasonably well standardized, particularly where the specifications of the American Petroleum Institute have become widely adopted. Capacity of standard size vertical steel storage tanks will vary from 2,160 bbl. as a minimum to 134,000 bbl. as a maximum; diameters range from 36 to 144 ft., and heights from 12 to 46 ft. under A.P.I. specifications.

The number, size, and spacing of tanks depend upon several factors: the area of the terminal site, foundation conditions, possible legal restrictions, compliance with fire-protection regulations, kind of commodities to be handled, and rates of loading and receiving. In cases where products are received by water only and climatic conditions do not permit year-round operation of ships, additional storage must be provided for terminal activities during winter months (Figs. 2 and 3).

The size and location of terminal sites being determined for the most part by economic factors alone, ground conditions to be encountered are frequently very poor and the design of adequate tank foundations often becomes a major problem.

Foundations may, however, vary from nothing but the ground itself to the construction of costly pile substructures. Where subsurface conditions are such that little or no settlement whatever will occur from the weight of a filled tank, the ground is levelled off, a layer or cushion of sand sometimes provided, and the tank placed directly thereon, no further provision being necessary.

Where the subsurface is soft but where ground conditions over the entire bearing area are uniform to the extent that equal loads will produce equal settlement, the amount of settlement at which decided failure of the subsoil occurs should then be determined from tests. From this an allowable maximum unit-bearing load should be decided upon which can be safely distributed over the entire area without approaching this point of failure.

In cases where this allowable bearing load will be considerably higher than the unit weight at the base of a filled tank under consideration, the tank may be safely placed directly on the surface of the ground and be permitted to settle at will, settlement of 6 in. or more being by no means uncommon.

In other cases where the unit allowable bearing load will be equal to, or nearly so, the unit weight at the base of the filled tank, serious consideration should first be given to the possible substitution of a tank of lesser height—but necessarily greater bearing area for equal storage—as a means whereby the unit weight can be so reduced that special construction of foundations will become unnecessary. Should this not be possible, consideration should then be given to additional support of the tank shell to produce more uniform load distribution, inasmuch as the weight of the shell constitutes a concentrated load around the tank perimeter considerably greater than the unit weight over the remainder of the tank base. Some construction methods which have been successfully used for relief from the effects of such concentration are herewith noted. One is the construction of a concrete ring—of tank diameter, not less than a foot wide, and extending down at least to below frost-level—and the placing of the tank shell directly thereon. Where the site is on filled and yielding ground, the ring must extend down to a good bearing stratum, and the fill inside the ring area in some cases be removed and replaced by good earth or sand. In localities where timber is more readily available and cheaper, and the earth confining advantages of a concrete ring are unnecessary, a circular timber mat of posts laid side by side radially on the surface of the ground, each post being 6 ft. long or more, has also proved an effective method for tank-shell support and load distribution.

Where ground conditions over the entire bearing area are not uniform, but where the maximum allowable unit bearing load of the greater part of the area will not be exceeded, construction of a reinforced concrete mat beneath the entire tank base may sometimes be used to distribute the weight of the tank more evenly and achieve even settlement.

Finally, where the allowable bearing load is decidedly lower than unit-filled tank weight, support by piling will be the final and most costly consideration. The driving of a ring of interlocking steel-sheet piling to form a circle somewhat larger than the tank itself, and the placing of the tank directly on the ground within the circle, has been

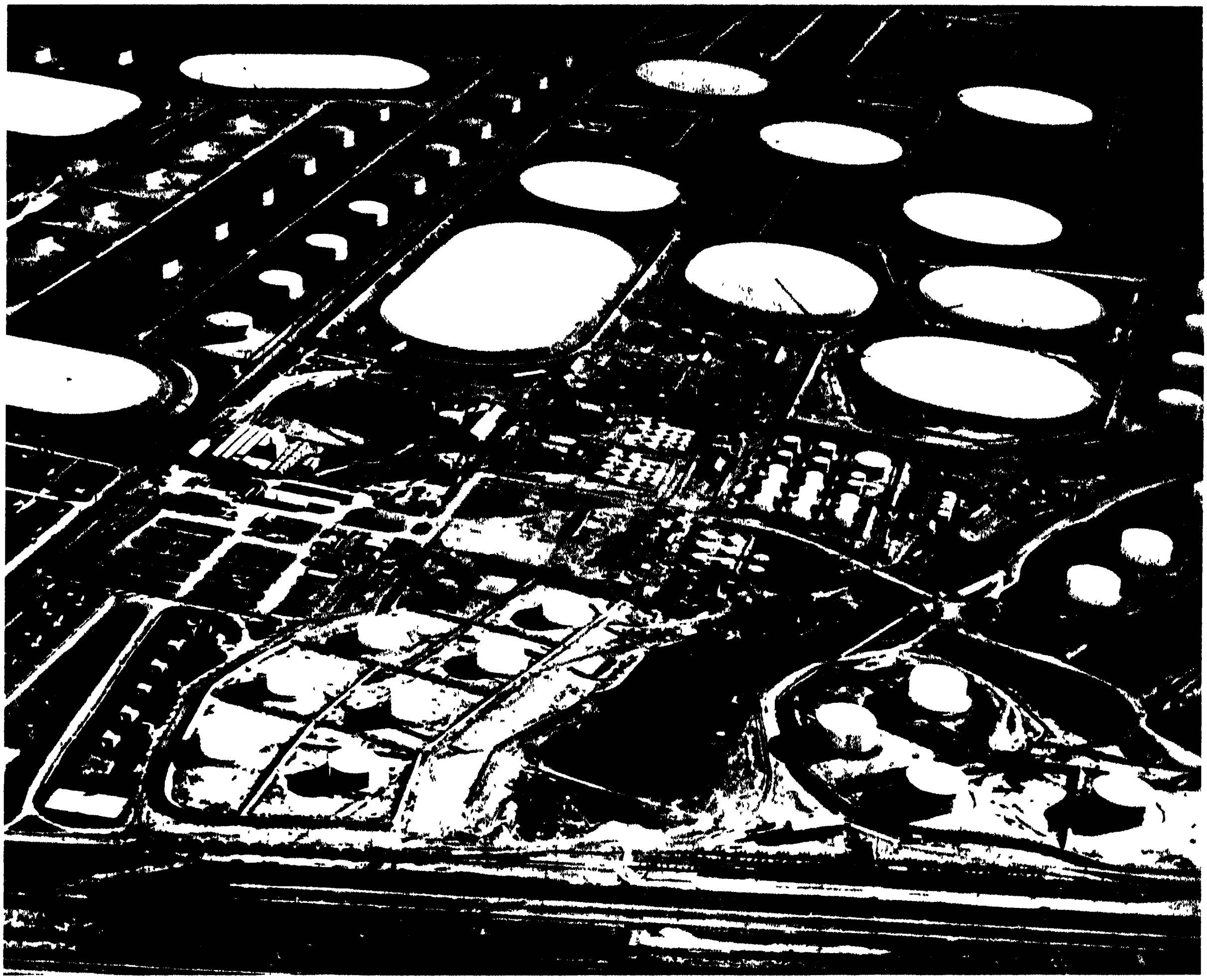

FIG. 2. Welmington tank farm

FIG. 5. A typical small terminal, showing wharf, storage tanks, elevated water tank, pumphouse, and boiler house

found recently to be a very effective and reasonably inexpensive form of pile foundation; the object, of course, being to confine the earth beneath the tank and prevent horizontal plastic movement until such depth is reached that the movement will be small owing to consolidation from weight of the earth above.

Bearing piles for tank support, driven at regular intervals over the entire bearing area, with a concrete mat covering over all, constitute the most costly and yet reliable type of foundation for bad subsurface conditions. Piles may be of timber, concrete, or composite timber-concrete construction with timber below water table and concrete above. Depth of drive-bearing piles has been briefly considered under 'Docking Structures'.

Mention should be made here of another use for piling in tank foundations, namely, the practice of driving very short 'stub' piling as close together as possible over the entire bearing area in an attempt to consolidate the upper ground mass and thus curtail upper plastic movement. Too frequently has this been done without any knowledge of the characteristics of underlying ground material, and in a short time the piling has become useless.

In conclusion, it should be kept in mind that a reasonable knowledge of subsurface conditions, together with results from adequate subsurface material tests when doubt is involved, can form the only safe and economical basis for proper foundation design.

Location of tanks may, in some instances, be of primary importance owing to the possible effect on nearby structures where soft subsurface conditions are present. A tank too near to a dock may cause failure of the dock due to increased horizontal earth pressure from either the weight of the filled tank, disturbance of the subsurface during tank foundation construction, or a combination of both.

It is common practice to 'cone up' or pitch tank bottoms from the centre towards the shell by shaping the underlying earth or sand cushion in order to facilitate tank drainage.

Steel storage tanks may be of welded or riveted construction—or a combination of both—and may have one of three different types of steel roof, depending upon the degree to which vapour loss from the stored product is to be controlled. Steel roofs may be of (1) rigid construction, such as the 'umbrella' roof (shell support only) for very small tanks, and the 'cone' roof (centre and intermediate supports) for larger and up to the largest tanks; (2) breather type, in which the roof is rigidly attached to the top of the tank shell, but is free to move up and down as a diaphragm, or 'breathe', within limits; and (3) floating type, in which the roof actually floats on the surface of the liquid and slides over the inner shell surface by means of properly designed shoes.

Choice of tanks for the various oil products to be stored, together with discussions on vapour losses, tank equipment, line connexions, painting and corrosion, and fire protection will be found elsewhere.

The surrounding of each tank by a firewall or dyke, of dimensions such that the volume which could be impounded within the firewall area would be 125 to 150% of tank storage, is a legal and insurance regulation frequently to be complied with. However, the value of fire walls from a general safety standpoint, whether to entrap boil-over from 'wet' oil storage in the event of fire, or for impounding protection only of any stored product in the event of unforeseen occurrences, cannot be over-estimated.

Firewalls may be of earth, reinforced concrete, or metal-sheeting construction, depending upon the storage space available, tank spacing, cost of construction, and legal restrictions. Safe tank-spacing practice will generally require a distance between tank shells of not less than the diameter of the larger tank, and, where products subject to boil-over are stored, the establishment of at least 50 ft. from the top of the firewall to the nearest tank. Proximity of tanks to property lines is generally governed by legal restrictions, or common-sense determination. Earth walls are constructed with a walkway at least 2 ft. wide on top, and a slope 1½ horizontally to 1 vertically on each side to grade; minimum concrete wall thickness should be 6 in. and preferably 8. 'Boil-over' protection for storage tanks containing wet oils requires the addition of inwardly deflecting metal copings, or 'splash boards', for the full length along the top of the walls. Adequate stairways and walkways should be provided within all tank areas.

Piping and Pumping Equipment.

Two major points for consideration stand out in the design of oil terminals: (1) flexibility of operation—that is, adequate provision for the transfer of any of the stored products between any two points in the terminal; (2) speed of handling—that is, choice of equipment to enable a tanker to receive or discharge its cargo with the utmost desirable dispatch. Much study of choice of location and size of equipment will be necessary to do this as economically as possible to the end that equipment investment plus cost of operation may be a minimum.

It is not possible here to touch upon terminal piping practice more than generally. Starting at the dock, it is common to find the suction and discharge oil-lines from tank storage terminating in loading lines—or pipe headers—running the length of the dock, underground or below the deck. From these headers risers are brought up at intervals sufficient to permit loading or unloading at fore, aft, and amidships if desired, each having either single or twin outlet connexions consisting of valve and elbow for attaching hose to ship. Hose is commonly flexible suction and discharge type, of rubber and cotton fabric construction with coiled metal insert to prevent collapse. Hose may be purchased in 20- to 50-ft. lengths, having steel flanges attached at each end and which may be bolted together to obtain the required length. A 6- or 8-in. diameter hose is commonly the largest in use on account of difficulty in handling the larger sizes, and small shipments are often handled with a 4-in. size.

In the off-shore type of terminal, oil-lines are laid under water out to anchorage where either they terminate in headers and valves on mooring piles, or are attached to flexible hose, the other end of which is attached to a buoy. Usually, a smaller auxiliary suction line is run out with the main lines and is connected to them at the off-shore end in order to pump off oil in the event of leakage.

Rates of loading or unloading tankers may vary from 2,000 bbl. per hour, for bunkering or barge shipments, to as high as 20,000 bbl. for tankers at the large terminals. Handling of light products will not be more than about 3,000 bbl. per hour per ship's compartment on account of proper venting of vapours formed. Having decided upon minimum and maximum rates of loading which will be satisfactory, the size of suction lines between tank storage and pump, and the size of pumps may then be determined. Positive suction head at the pump is, of course, desirable under all conditions of flow; however, at certain stages of operation, the size of lines required may make this

economically impossible and the existence of some negative head becomes imperative. Minimum allowable absolute pressure in the suction line should not be less than the vapour pressure of the product being pumped, owing to excessive turbulence and vapour pocketing in the lines below this pressure. Where vaporization is not a factor, as when pumping viscous products, the allowable suction head should be governed by the manufacturer's recommendations for the pump. Suction lines commonly vary from 10 to 20 in. in diameter, and, in general, a rate greater than 6,000 bbl. per hour per pump for gasoline cannot be safely handled at the dock.

The number of oil-lines required between dock, pumps, and storage will vary with the number and type of products to be handled, and the degree of contamination permissible. Discharge lines may vary in size from 8 to 16 in. in diameter, the size depending upon the product to be handled, the quantity and maximum velocity desirable, and the allowable line-pressure loss. Contamination of one product with another through the use of common pumps or piping is restricted as follows: No commingling of coloured or high 'anti-knock' gasoline with white or lower grades, and the mixing of white grades with each other permitted to a limited extent only; no possible addition of gasoline to kerosine or fuel oil that may lower the flash-point of the latter; no 'dirtying' of white products; no carrying of heavy oil into light products; no addition of light products to heavier fuel oils that may cause lower flash-point; no commixing whatever of lubricating oils. Washing out of pipelines in order to handle contaminating products in the same line should never be contemplated in design, and should be avoided in practice unless extremely unusual conditions warrant.

Oil-lines within the terminal area are commonly laid above ground for reasons of cost, construction, accessibility, leak detection, drainage, and protection from corrosion. Greater provision for expansion must ordinarily be made in this case than for underground lines. Several types of pipeline-expansion joints have been used with success, but a freely supported or suspended line above ground, with its one or more incidental pipe bends, will often require no further provision for lineal pipe expansion. Thermal expansion of liquid within a line is commonly provided for by means of automatic pressure relief valves placed in small by-pass lines around the main block valves and set to open at suitable relieving pressures. Drainage requires a slight sloping of lines to a low point and the installation of small drain valves to drain-pits or to service-pump suction. Most terminals are operated with lines kept filled or 'wet' at all times, and these, as a rule, are drained in cases of emergency only.

Oil-lines should be connected to tanks only with such fittings that will permit movement of the tanks during settlement or expansion, and thus prevent undue stresses in pipe or tank which might cause leakage. Suction lines are commonly connected on the inside of tanks to a 'swing' line which consists of a length of pipe fastened to the suction outlet near the tank bottom with a flexible joint terminating in an elbow fitting. The swing line may be raised or lowered with a suitable winch and cable device attached to the tank wall outside, so that the liquid within the tank may be taken off at such a level that bottom sediment and water will be excluded.

Lines should be manifolded at the pumps to permit the full flexibility of operation described in the first paragraph, and to provide for future connexions or temporary crossovers. The placing of valves requires close study of flexibility of operation, avoidance of contamination of products, saving of storage in the event of leakage, and blocking-off lines for repairs.

Lines are commonly of standard weight, welded steel pipe, with welded or flanged connexions. Fittings and flanges should be of steel; valves above 2 in. in size should be standard pressure, flanged, all-steel gate valves. Cast-iron valves and fittings should not be used in any location where fire or mechanical shock may occur, and for these reasons should be excluded from oil-line construction.

For the handling of asphalt or very viscous oils, where steam is available at the terminal heat may be transferred to the oils in the following ways:

(*a*) Steam coils within the storage tanks.
(*b*) Small heat exchangers surrounding the oil-lines outside or within the tanks.
(*c*) Jacketing or enclosing the oil-lines within larger steam-lines, or the laying of small steam-lines outside and directly against the oil-lines.

Additional pipelines to be required at the terminal might include:

(*a*) A line conveying oil-contaminated ballast water from ships, together with oil drippings drained from the dock, to an oil-recovery system or other point of disposal.
(*b*) Fresh-water line from point of supply to ship.
(*c*) Fire, water, and foam lines. Requirements for fire, water, and foam lines will be found in another section of this article.

Selection of pumping equipment will be determined to a large degree by the kind of power to be used, type of service required, characteristics of products to be pumped, rates of discharge and maximum heads to be pumped against (Fig. 4.)

Choice of power is likely to be influenced by several factors. Purchase of electric power from a power company commends itself in most instances where such source is available; however, the following points should be well considered before final decision is made:

1. The cost of construction and operation of a small electric power unit, oil or steam driven, as part of the terminal itself, may be less than the cost of service offered by the power company. In addition, in the event that such a unit were steam driven, steam would be available as an additional type of power, and could be on hand for heating purposes and for supplying to ships at dock.
2. The 'demand', or minimum monthly charge, made by power companies for maintaining instant service to the large connected horse-power generally to be found at a marine terminal, often runs the monthly unit power cost extremely high owing to short and infrequent periods of equipment operation. The use of Diesel, steam, or electric power produced at and by the terminal itself for that part only of the major equipment most intermittently operated will lower this charge for purchased power, and may possibly result in considerable savings in total power costs.
3. Assuming the rates offered by the power company to be attractive, current characteristics must be thoroughly desirable for the equipment under consideration, and proof of reliability of power service must be such that emergency sources of power to be on hand at the terminal may be a minimum.

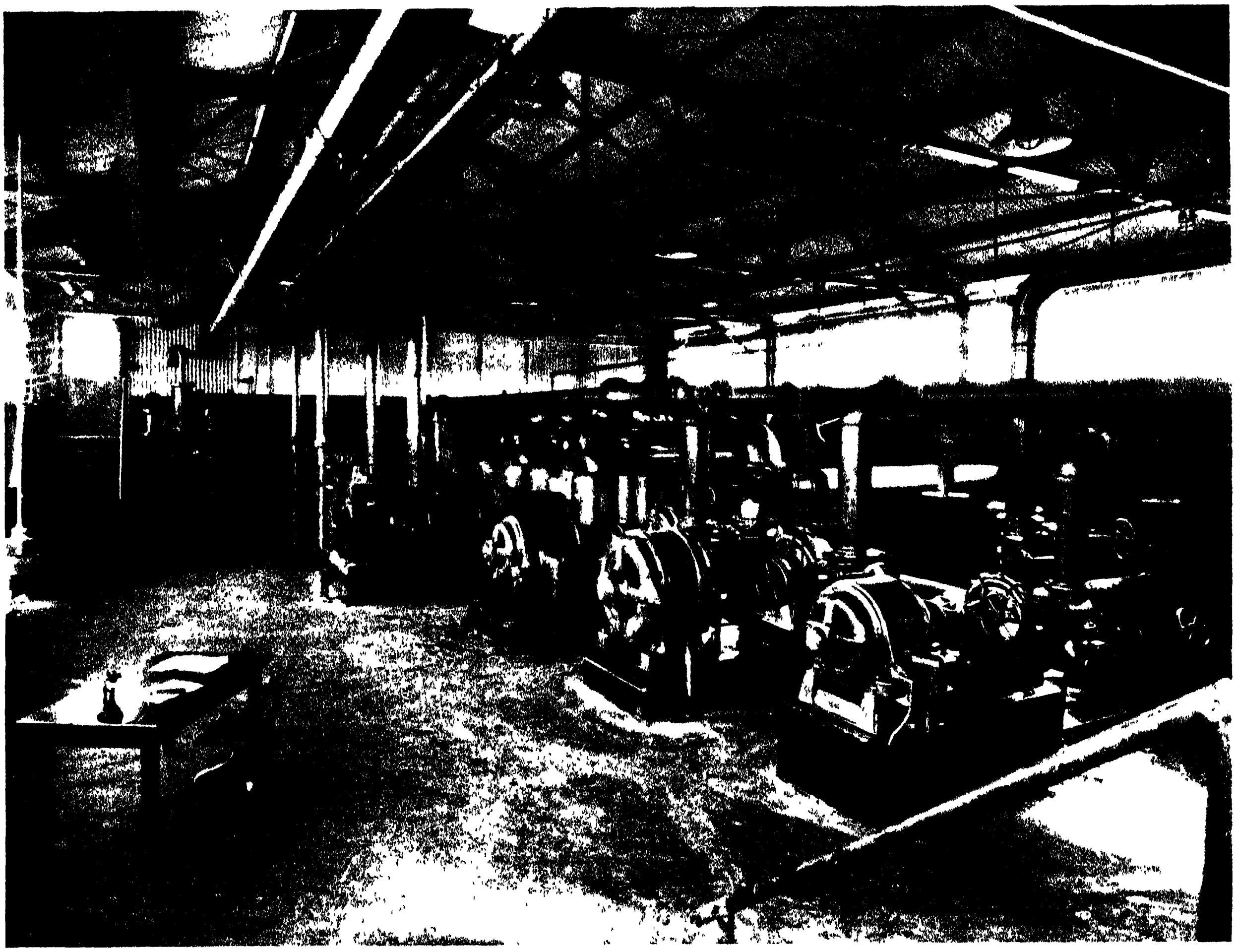

FIG. 4 Interior of dock pumphouse centrifugal pumps in foreground used for pumping gasoline, kerosine, and gas oil Reciprocating pumps at rear used for fuel oil

FIG. 7. View of oil docks. Note derricks for handling hose, floodlight at rear, at extreme left an inclined belt conveyor for loading petroleum coke in bulk

Pumps may be divided into three general classes:

1. Centrifugal.
2. Reciprocating.
3. Rotary.

The centrifugal pump consists essentially of one or more impellers rotating at high speed within a surrounding casing. The rotation of the impeller causes liquid within the pump to rotate, to be thrown out centrifugally against the casing wall under pressure, and to be conducted or discharged from the casing under this pressure. Being dependent upon high and generally constant speed for operation, this pump is usually direct driven by steam turbine or electric motor. It may be of the single or double suction type—that is, liquid may be taken in on one or both sides of the impeller—and have one or more 'stages', or impellers, depending upon head requirements. Every centrifugal pump is designed to operate at maximum efficiency under a definite condition of speed, head, and capacity. Advantages of the centrifugal pump are:

(*a*) Compactness as a unit, small space and light foundation requirements.
(*b*) Simplicity of construction, smoothness of operation, and high efficiency.
(*c*) Ability to change discharge when head is changed, and maintain good efficiency over a reasonable range of discharge.
(*d*) Adaptability to handling large quantities at very low heads, thus resulting in low investment cost per unit quantity handled.
(*e*) Impeller action which permits throttling or full closing of discharge valve while the pump is in operation.

Disadvantages are:

(*a*) Low suction lift value.
(*b*) At times, the changing rate of discharge with change of head.
(*c*) Limitations and low efficiency in the handling of viscous fluids.

The reciprocating pump consists simply of one or more cylinders into which liquid is sucked on the intake stroke of a piston, and discharged on the discharge stroke. It is usually driven by a direct-connected steam piston, although installations employing belt, gear, or chain drive by steam turbine, Diesel engine, or electric motor are to be found. It may commonly be of simplex, duplex, or triplex (one-, two-, or three-pump cylinders), and be single acting (one working stroke per revolution utilizing only one side of piston) or double acting (two working strokes per revolution utilizing both sides of piston). This pump is essentially a low-speed, low-capacity pump, and is most suited to the handling of small quantities at high heads. Its discharge is directly proportional to its speed and, unlike the centrifugal pump, it may change speed with little resultant change in efficiency. Advantages of the reciprocating pump are:

(*a*) Simplicity of control, operation being regulated generally by simple steam-valve manipulation.
(*b*) Constant rate of discharge regardless of change in head.
(*c*) Capability of handling oils of high viscosity, and at all temperatures, with little change in efficiency.
(*d*) Greater available suction lift than for a centrifugal pump.

Its disadvantages are:

(*a*) Extreme size and weight for handling moderately large quantities.
(*b*) Pulsating discharge.
(*c*) Extremely low efficiency under all conditions of operation.
(*d*) Positive displacement action which makes throttling or closing of the discharge valve hazardous while the pump is in operation, even though a by-pass valve relief is provided.

The rotary pump is a positive displacement pump, the displacement being accomplished by rotary motion of various kinds according to the make of the pump. It, also, is a slow-speed, low-capacity pump with discharge varying directly with speed, and is usually driven by Diesel engine, turbine, or electric motor through reducing and variable speed-gear trains, belt, or chain drives. Its characteristics are similar to those of a reciprocating pump, with the following exceptions: cost, size, and weight of the rotary pump are much less for the handling of moderately large quantities, also more uniform discharge is attained with less pulsation, and it is better adapted for handling very viscous products owing to its having no valves; the reciprocating pump is more simple in operation, however, and will resist wear from abrasive products to a greater degree.

Terminals will require some or all of the following pumping equipment:

1. Pumps to be installed within terminal pump-house.

(*a*) For loading out tankers from storage: low viscosity products—single-stage centrifugal pumps of high capacity, 5,000 to 10,000 bbl. an hour, suitable for low discharge head operation; high viscosity products—positive displacement pumps for smaller quantities and high discharge heads. As a rule, the maximum economical size for reciprocating pumps at a terminal will not exceed 300 gal. per min., and for rotary pumps about 500 gal. per min.
(*b*) For bunkering or barge shipments: rate of required handling is low so that one or more of the pumps on hand for loading high viscosity products to tankers may be used. Light products can be handled by transfer pumps.
(*c*) For transferring from one part of terminal to another: one or more additional single-stage centrifugal pumps of medium capacity and head characteristics for light products, together with the use of the above-mentioned loading pumps for viscous oils.
(*d*) For general service: the use of a separate reciprocating pump has been found admirable in some cases for such varied service as draining lines, pumping oil drainage or ballast water to points of disposal, providing pressure in pipelines to remove congealed oil.

2. Pumps within terminal pump-house or in separate foam pump-house.

(*a*) Pumps for fire protection. Requirements regarding number of pumps and their size will be found in another section.

3. Pumps in other parts of the terminal.

(*a*) Occasionally, separate small pumping units must be located within the terminal where the topography

or other conditions are such that they cannot be advantageously placed in the terminal pump-house. Examples might be: at the dock, for oil drainage, or ballast water handling; at other points of drainage throughout the terminal; at tank-car unloading spots. This practice, however, should be avoided whenever possible.

Ideal location of the terminal pump-house will, of course, be that which requires very short suction lines between pumps and tanks. Seldom is this possible, however, owing to tank spacing and firewall construction, topographical features, the area of free space required for the movement of vehicles within the terminal property, and other limitations.

All pumps should be controlled directly at the pump-house; however, additional remote control stations are sometimes provided, but their desirability from the standpoints of safety and reliability of operation can be questioned. Emergency electrical disconnect devices should, however, be provided wherever the slightest occasion for their need might arise.

Principles of Operation

The functions of an ocean terminal, reduced to the simplest terms, consist of receiving, storing, and dispatching oils for either inward or outward movement. In many instances the terminal may be charged with the duty of blending and packaging of the various classes of refined products. In most cases practically all the oil is handled in bulk and the operations are not very complicated.

It is rather difficult to classify the separate operations necessary for the efficient functioning of a modern terminal, since the successful operation depends on the co-ordinated action of a well-trained crew of wharfmen, inspectors, testers, and others. In general, the functions may be roughly divided into those concerned directly with loading and unloading of ships and those which are incidental to shore operations.

Shore operations consist mainly of receiving oil from and dispatching oil to inland points and of transfers between termini. These operations are quite simple, but vary greatly with the individual terminal. The operations necessary to loading and unloading of tankers are, however, more or less standard for all terminals and will be discussed at length. Fire-protection principles as applying to terminals are also described.

Loading and Unloading of Ships.

The economics of tank-ship operation demand that the ship should spend as little time as possible in port while loading and unloading, and hence spend a maximum of time in steaming. In most charter parties or contracts there is generally a time limit set for total time consumed in loading and unloading which, if exceeded, results in heavy costs for demurrage.

For these reasons, all possible work incidental to the loading or unloading of a tanker should be completed before the arrival of the ship. The oils to be loaded should have been tested and their quality certified. The proper tanks, valves, and pumps should be made ready and, if necessary and possible, the loading lines flushed out and completely filled with the oil to be loaded.

When the ship arrives at the dock, the ship's lines are made fast to mooring cleats or 'dolphins', and the ship is warped into its berth. As soon as the ship is moored, the oil inspectors, who may be licensed neutral parties or members of the terminal staff, board the ship and inspect the tanks for possible contamination either from residues of former cargoes or from ballast. Inasmuch as the ship generally arrives with tanks free of gas and with the hatch covers unbolted in order to facilitate inspection, it is usually sufficient and possible to make only a visual inspection from the hatch, using an electric hand-lamp for illumination.

The terminal executive at this time checks up with the officers of the ship in regard to the cargo to be loaded, and arranges any special procedures which may be necessary.

The pipelines on the wharf are connected to the ship's piping manifold by means of specially designed flexible hose. A sufficient length of hose must be used so that plenty of slack is available to compensate for motion of the ship and to allow for change in draught of the boat as loading progresses. Small low-wheeled carriages or sledges are used on the wharf to move hose from place to place, in order to prevent wear and tear and to reduce the number of men necessary for handling the hose. Derricks equipped with hand- or motor-powered winches are used to swing the hose into position and to support it while it is in use, thus reducing the strain on the flange connexions as well as preventing chafing. Separate hose must be used for the white products, gasoline and kerosine, and the black products such as fuel oil. Hose should be tested periodically to its full designed working pressure and leaky or defective lengths discarded.

At the time the hose is connected, a heavy stranded copper cable is connected between the ship's piping and the wharf piping to provide a ground for static electricity. The wharf piping also should be well grounded.

The wharf crew having connected the hose, loading may commence as soon as the ship's officer in charge of loading signifies that all is ready.

When loading volatile products such as gasoline or casing-head gasoline, it is generally required that all ship's fires be extinguished until loading has been completed. In this event, steam or electricity must be supplied from shore to operate auxiliary equipment on the ship.

The rate of loading depends upon the capacity of the pumping equipment, and may be as high as 20,000 bbl. per hour at some terminals handling crude oil on the U.S. Gulf Coast. The usual loading rate for gasoline is much slower than this, 5,000 bbl. per hour being an average rate, with higher rates for loading very large tankers. When the ship's tanks are nearly filled, the rate of loading is reduced in order to minimize danger of overflowing.

The midship tanks are generally filled first, and the fore and aft tanks last. As the last tanks are being filled, the draught of the ship is checked to be sure that the lawful draught is not exceeded. A loading mark, known as the Plimsol, is painted on the side of all ships to indicate the permissible draught. The permissible draught varies with the season of the year, and is less in winter than summer.

Loading should always be effected through the ship's manifold except in very special cases. It is not considered good practice to 'load overall', that is, by opening a tank hatch and dropping the end of the loading hose into the tank. This procedure is dangerous from the standpoints of generation of static electricity and the release of vapours from the tank.

The full volumetric capacity of ship's tanks, allowing about 2% for expansion, is usually greater than the deadweight tonnage capacity of the boat, except when loaded

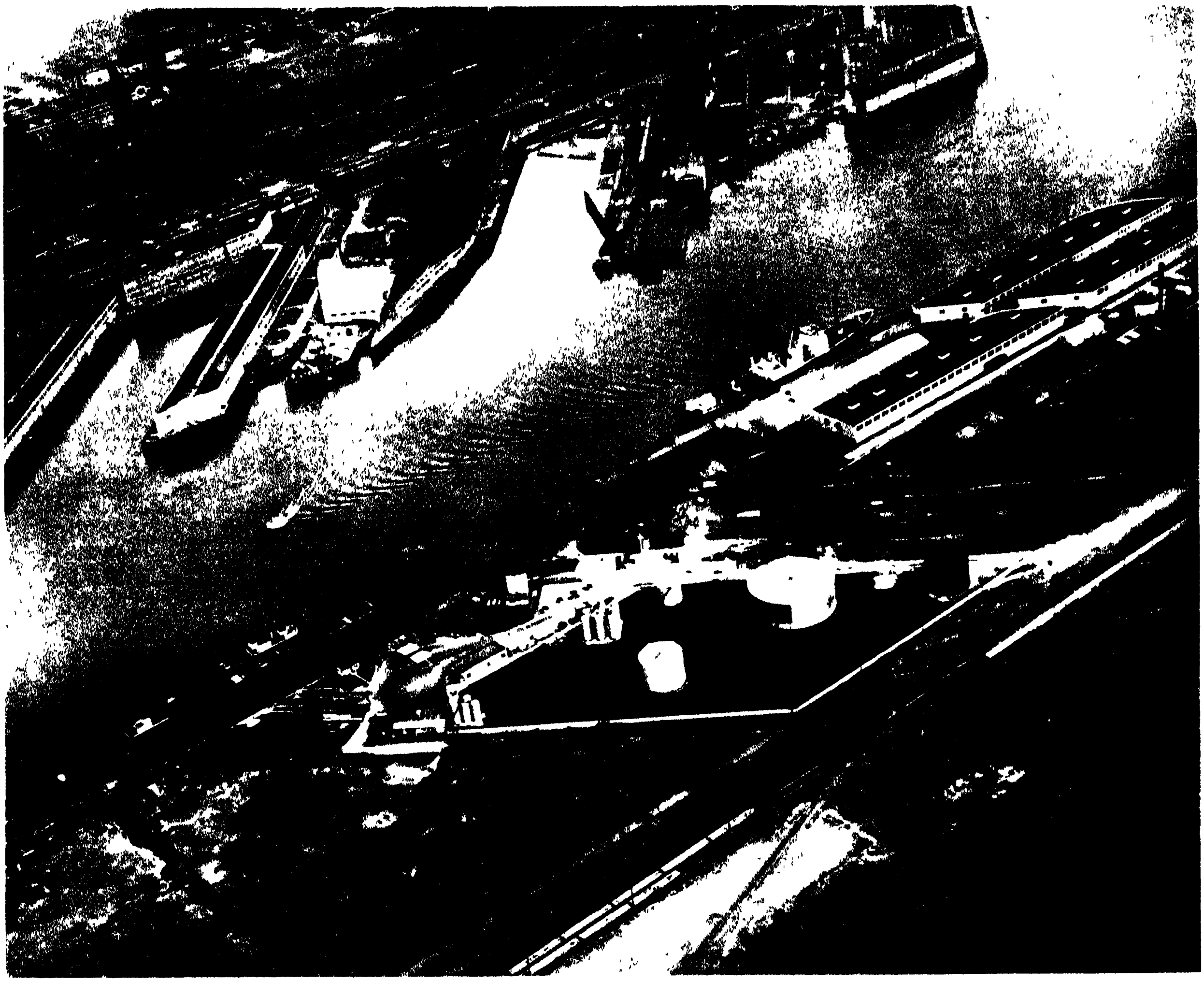

FIG. 3. Harbour island terminal installation

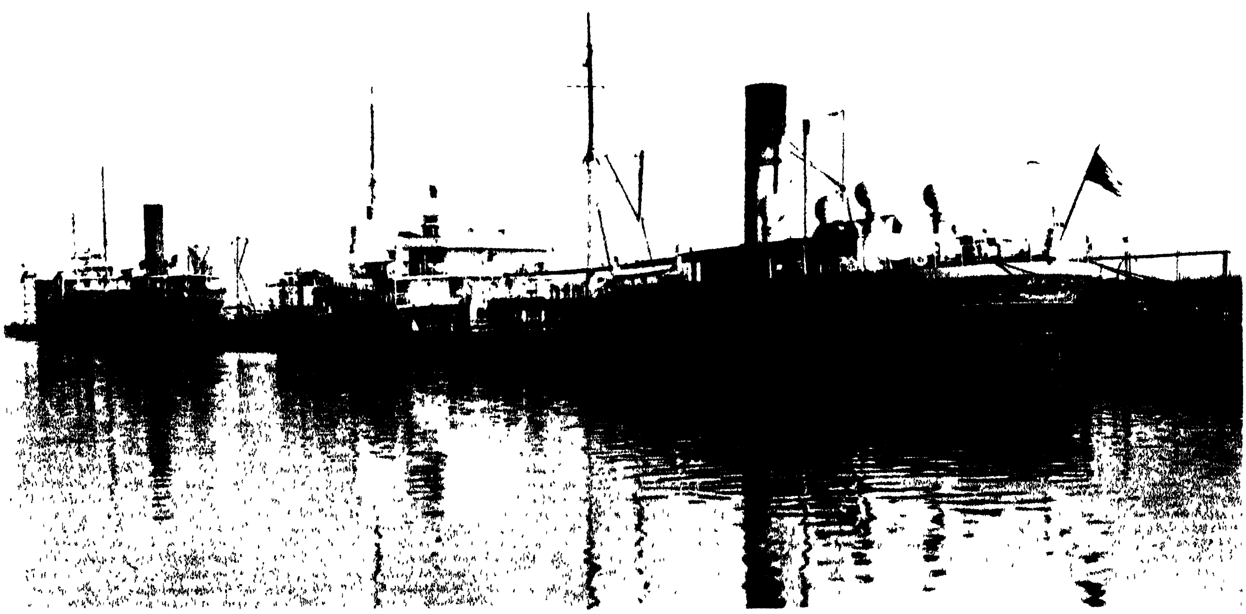

FIG. 6. Ships loading at a sea terminal

with products having a very low density, hence there is generally some free space left in the fore and aft tanks. The relative quantities in these tanks may be adjusted during the voyage in order to trim the ship as bunkers (located nearer the stern) are depleted.

When all tanks are filled to the required level, the loading pump is stopped, the loading-line valve on the dock is shut off, and finally the ship's valve is closed. The loading-line valve may be shut off first very slowly if the loading pump is of the centrifugal type, but should never be shut off first if the pump is a positive displacement type. Above all, the ship's valve must never be shut off so that full pump pressure is exerted on the hose.

It is desirable at all times—and imperative during the 'topping off' operation—that the pump man at the shore station stand by his pumps, ready to stop them instantly when so signalled from the wharf. Telephone or electric signal systems are best, but semaphore signals may be used when visibility permits. Remote control of electrically driven pumps is practical in some cases.

When loading has been completed the hose is disconnected, care being taken to prevent spillage of oil, and the pipe connexions are sealed by bolting on blind flanges.

The ship's tanks are then gauged and samples are taken from the various tanks. Usually it is unnecessary to await the testing of these samples before the ship departs, unless contamination is suspected. Samples taken and tested while loading is in progress will reveal whether the material being loaded is free of any possible contamination, due to leaking valves or manifolds. Before loading is started the shore tanks are tested to be sure that the cargo is satisfactory.

Shore tanks are gauged before and after loading. Thus there are two independent measurements of the amount delivered, the shore-tank gauges and the ship's tanks. A third check, but not of great accuracy, is that made by noting the change in draught of the ship due to loading and obtaining the weight of the cargo from the ship's displacement tables. These tables show the dead-weight tonnage per inch of draught. Suitable corrections, either plus or minus, must be made for the net change in weight of stores, water, and bunkers occurring during the loading period. The displacement, which is the weight of water displaced by the ship, is figured on an average density of sea-water at 60° F. (sp. gr. = 1·025). For fresh-water or other waters having a density significantly different from sea-water, suitable corrections must be made in the figures given in the displacement tables.

Unloading operations are carried out in practically the reverse order of loading operations. When the ship arrives at the dock, the cargo tanks are sounded for water, ullages, temperatures, and samples are taken on each tank. The shore tanks which are to receive the cargo are gauged and the pipelines and valves are lined up. Hose connexions and static electricity grounding cable bonds are made between ship and wharf, and unloading may then commence. When unloading volatile products such as gasoline, it is safe practice to extinguish the fires in ship's boilers and to supply steam from shore for operation of the unloading pumps at installations where steam is readily available.

Cargo is unloaded by means of pumps located in the pump-room of the ship. Generally, the rate of unloading is less than the usual rate of loading owing to the smaller capacity of the ship's pumps.

When unloading is completed, it is good practice to again inspect the ship's tanks or take ullages in order to make sure that all cargo has been pumped out. The shore tanks are gauged and all data recorded in an 'Unloading Report'.

Documents.

A written record should be kept covering all oil movements to or from the terminal. These may take the form of a daily stock report on all oils stored in the shore tanks. This record is made up from the gauger's and pumper's daily report sheets, and inasmuch as these sheets show the actual gauges, temperatures, and water soundings, and are the original source of all other stock reports, they should be carefully preserved for at least six months.

In addition to these routine reports, there are many special reports and documents which must accompany a shipment of oil by tanker. These documents consist of the following:

Bill of Lading. A document specifying the quantity and nature of the materials shipped aboard a vessel, and signed by the Master thereof, acknowledging receipt of the cargo and undertaking its safe conveyance (perils of the sea excepted) to the consignee.

Statement of Quantity. A statement which identifies the shore tank or tanks from which cargo was loaded and which shows all pertinent data with respect to shore-tank gauges, temperature of oil, volume delivered, specific gravity of cargo, and weight of cargo. Any other pertinent data in regard to quantities are shown.

Statement of Quality (Quality Certificate). A statement showing the results of analyses of material delivered from shore. It is customary to execute a separate statement for each shore tank used.

Ullage Report. After completion of loading, a representative of the terminal or, in some cases, a qualified inspector (neutral third party) and the First Officer of the vessel jointly take ullages on each of the ship's tanks containing cargo. These ullages are shown on a special report which is signed by both parties.

Time Report. This report merely details the experience of the vessel with respect to the time elapsed while at the terminal dock. The time of arrival, time when moored, and time loading starts and finishes are indicated. Any interruptions of loading operations are also shown, together with appropriate remarks as to whether such interruptions are for ship or shore account. This report is signed by the vessel's chief officer and a representative of the terminal.

Shipments between foreign countries may require the execution of one or more of the following special documents:

(*a*) Special Manifest. In some cases this must be viséd by a Consul representing the country to which cargo is destined.
(*b*) Certificate of Origin. May require a visé.
(*c*) Regular bill of lading must be viséed.
(*d*) Special Consular Invoices.

Personnel and Organization.

The personnel and management organization of a terminal need not be complicated. All operations are generally managed by the terminal superintendent. The operating crew may consist of a wharf foreman who has charge of all

operations at the wharf and the wharf crew; also, a gauger and pumper are required to handle operations in the storage-tank area. Generally, an oil-inspection laboratory in charge of a competent chemist is necessary at the larger terminals. At smaller terminals it is generally cheaper to employ licensed commercial inspectors at a fixed fee for each cargo inspected.

The organization, of course, must conform to the complexity of the operations at the individual terminal, but in most cases the cost of operations will be decreased by allowing considerable latitude in job classification and the duties assigned to any particular man. For instance, when there is no ship in dock, the wharf crew may be profitably employed in small maintenance and repair jobs.

Fire Protection.

It is the purpose of this section to call brief attention to the more salient requirements for fire-protection practice at sea terminals which may escape notice or mention in other discussions on fire protection in oil-storage areas. Causes of combustion, the action of various agents in extinguishing fires, and the installation of fire-fighting systems and equipment are discussed fully in other sections.

The amount of fire protection afforded at a sea terminal will often be far from the complete installation to be found at oil refineries or bulk-storage stations within populous areas.

In all cases, a high-pressure water system is essential, whether supplied from city water mains direct with or without booster pumps at the terminal, or from other sources to terminal pumps. Well-protected terminals will be equipped with foam-generating equipment, now of the dry-powder-and-hopper type almost exclusively, which can be connected up to adequately spaced hydrants throughout the site. Strategically located hose carts together with foam-application devices within each tank complete the foam equipment. Water only, without foam, is used for protection of buildings and for tank-cooling purposes in case of fire. Terminals less fully protected will have no foam, and may depend upon municipal fire-fighting equipment to augment their own forces.

Hand chemical fire extinguishers are commonly to be found at all terminals, and should be well distributed near all structures such as docks, pump-houses, and other buildings. Portable foam apparatus or extinguishers of the liquid carbon dioxide type are useful for oil fires, with the non-conducting features of the latter being especially commended where fires near electrical apparatus are likely. A plentiful supply of sand in buckets for smothering small fires is another common requisite at all docks and piers.

Safe installation of electrically powered equipment within vaporous areas should receive the utmost consideration. The use of explosion-proof electric motors with fully enclosed switches and starting devices is essential. In oil pump-house design it is often possible to separate motors from pumps by means of a curtain wall, so that ordinary electrical equipment may be safely installed. Where Diesel or other types of internal-combustion engines are the motive power, all exhaust pipes should be carried to points well outside of danger, and in oil pump-houses full curtain-wall protection should be afforded between pump and engine. Steam power must be generated by boilers located in a definitely approved area. All lighting fixtures within the oil pump-house, at the dock, or at other points near to oil-handling equipment should be of an approved explosion-resisting type.

Operations should at all times demand the safety and precautions common to all areas where oils are being stored or handled. Piers and docks should be carefully maintained; decks kept free of rubbish and unnecessary articles, pipe and fittings inspected periodically to see that no dangerous strain has been put upon them due to movement of wharf structure, and walkways kept in safe condition. Pipelines should be thoroughly identified for the products they are conveying by painting with appropriate colours. All lines and equipment should have adequate grounding and bonding connexions to carry off static charges, and hose should be grounded from end to end through its metal insert. Smoking on any part of the property should, of course, be strictly prohibited, and equal restriction should apply on board ship as soon as she is berthed. It is safe practice, though not always feasible, to have all fires on board the tanker extinguished, and in no case should naked lights be allowed in the loading zone. Other vessels having fires and open lights should not be permitted alongside the tanker during oil loading or unloading operations.

THE MODERN TANKER

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THE design of a modern tanker for the carriage of a variety of petroleum products in bulk has to comply with many essential conditions, such as safety, comfort for the staff and crew, and economical running costs, whereby interest is earned on capital invested having regard to amortization, amongst other running costs.

In the early days of the transport of bulk petroleum from 1886 and onwards, the tanker was primarily designed to carry only kerosine for illuminating purposes, a product which had hitherto been transported from America and the Black Sea to the United Kingdom and the Continent in barrels. It was only necessary, therefore, to design a vessel which would have sufficient capacity for the dead weight of cargoes of a uniform grade, carried on a similar route, year in and year out, the cargoes being always of a homogeneous nature.

The modern tanker, in order to meet present-day requirements, carrying a variety of products at the same time, must be designed to carry liquid cargoes of widely divergent specific gravities, flash-points, viscosities, and to carry these cargoes on different trade routes.

Specific gravities of the oils to be transported vary from 0·650 for casing-head gasoline, which requires 55·34 cu. ft. capacity for 1 ton, to 1·0 for heavy fuel and for creosote oil, which require only about 33 cu. ft. per ton.

To enable a vessel to carry a full dead-weight quantity of the lighter grades of oil cargo, including the requisite amount of bunker oil, stores, and fresh-water for the projected voyage, the cargo tanks must have space capacity in order that the vessel can be loaded to its full dead-weight carrying capacity, so that she is down to the Lloyd's Freeboard marks when leaving loading port.

When heavier grades of oil, which occupy less space per ton weight, are to be loaded, the vessel will have the full dead weight on board without having all the available cargo space in use. The subdivision of the cargo space into tanks or compartments is arranged in such a manner that certain tanks can be left empty or partly empty without any undue strains being placed on the structure of the vessel, and at the same time the tanks which contain oil are filled to the requisite height to prevent the possibility of damage occuring to the decks or bulkheads due to unrestricted movement on the surface of the liquid cargo.

The vessel must also be designed to permit more than one grade of cargo being carried on the same voyage without fear of contamination of the various grades, and in addition to the spacing or grouping of the tanks (the various groups being divided by means of pump-rooms, or coffer-dams) careful consideration has to be given to the arrangement of the pipelines by means of which the cargo is loaded and discharged.

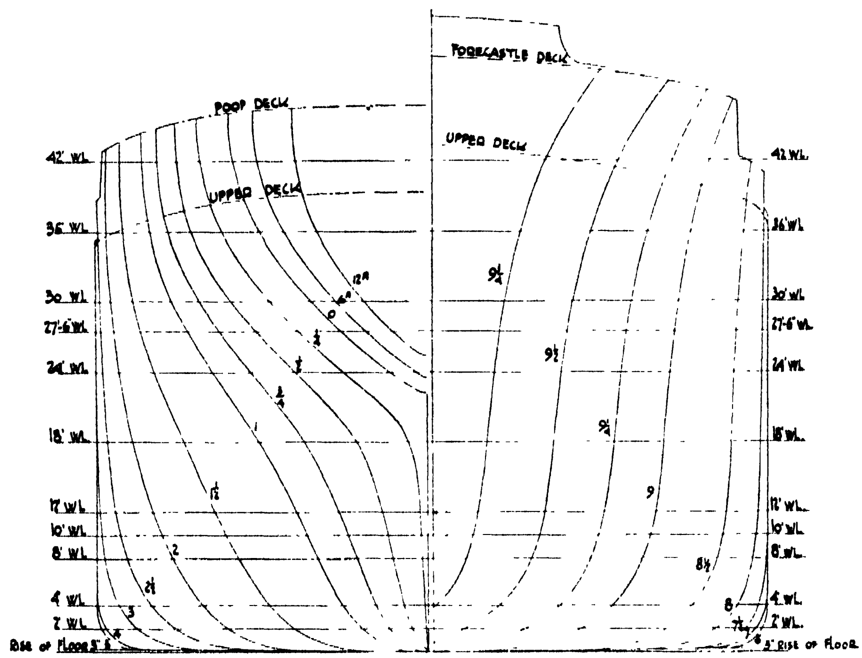


FIG. 1.

In addition to the above, a certain amount of space has to be provided for the purpose of carrying a limited quantity of packed products, such as benzene or kerosine, lubricating oil, &c., in drums or cases containing two 4-gal. tins, or paraffin wax in bags, &c.

Certain constructional precautions for the safety of the vessel and cargo against risk of fire or explosion, as well as the usual perils of the sea, have to be embodied in the design, and last but not least, the welfare and comfort of the staff and crew in the matter of accommodation and facilities for storing and preserving fresh provisions and preparing them for consumption.

In regard to the means of propulsion, the modern tanker

designer relies almost solely on the Diesel-engine for this purpose, and in most large ocean-going vessels the steam-engine in all its various forms has been superseded by the Diesel-engine in practically every tank vessel constructed during the past 8–10 years, excepting ships for special trades.

The Diesel-engined vessel is more economical than the steam-engined vessel. Whereas a steam vessel of, say, 8,500 tons dead weight requires bunker space for a consumption of about 19–24 tons of oil fuel daily for a speed of 12 knots, a supercharged Diesel-engined vessel of 12,500 tons dead weight requires bunker space for 12 to 13 tons daily fuel consumption only. This gives a far wider range of travel as well as making it possible for the Diesel-engined vessel to bunker at the producing centres for a round voyage without shutting out cargo.

In addition to the foregoing, consideration has to be given to any special trades on which the vessel may be employed, and ports with limitations, such as draught, dimensions of locks, special mooring facilities, necessary gear for lifting shore hoses on board, arrangements for loading or discharging over the stern, as well as any special regulations imposed by the governments of the various countries to which the ship will trade, have to be taken into account and embodied in the general design.

Bearing the foregoing in mind, the design of the desired vessel can be proceeded with, and such items as the form of the hull to carry the required dead weight at the most economical speed as well as calculations for strength can be worked out, and as a typical example, particulars and a description of the new vessels which have recently been delivered to the Royal Dutch-Shell group will be given.

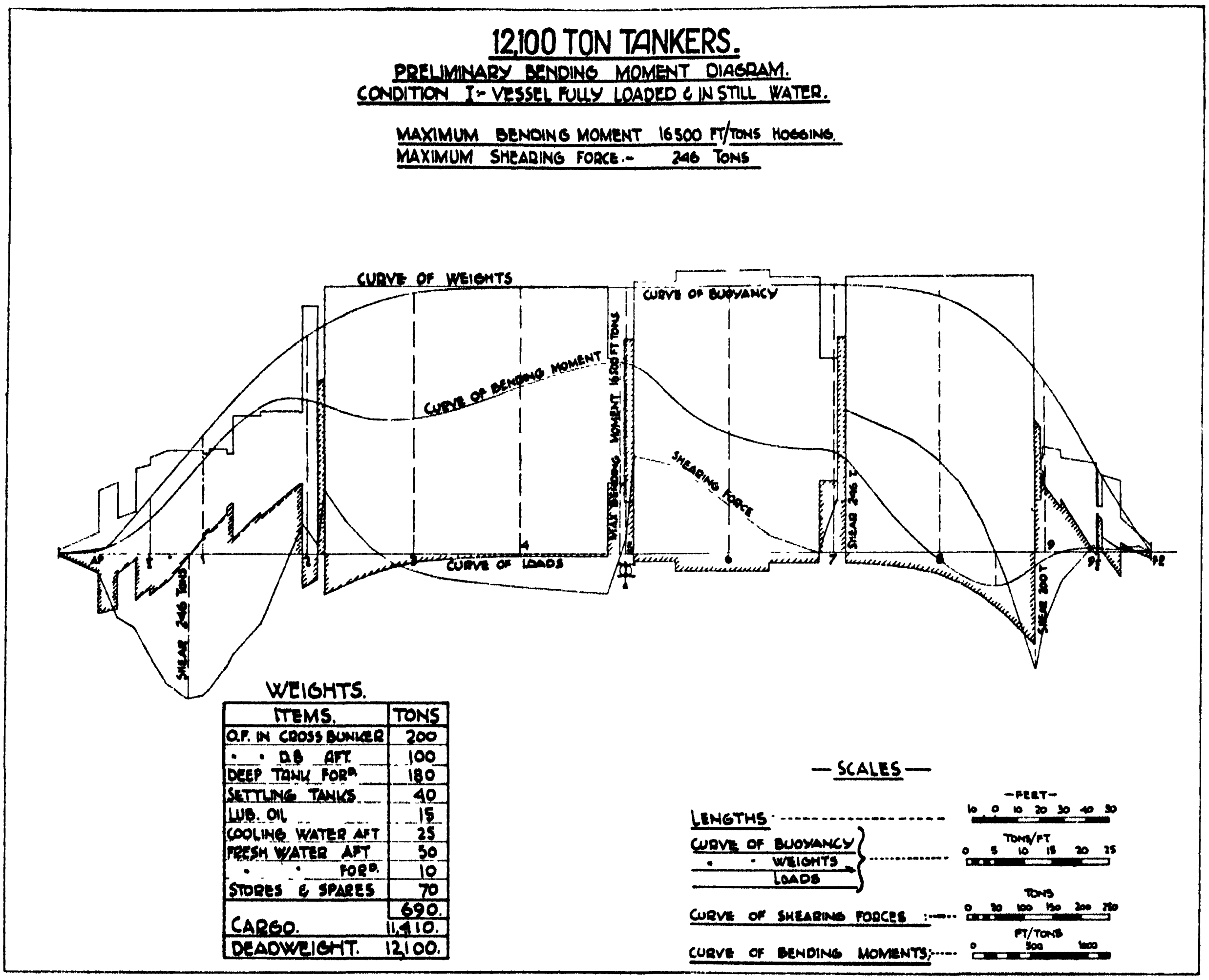


FIG. 2.

The dimensions decided upon to meet the considerations enumerated above were:

Length B.P.	460 ft.
Breadth (moulded)	59 ft.
Depth	34 ft.
Draught summer freeboard	27 ft. 6 in.
Dead weight	12,100 tons
Displacement	16,700 tons
Trial speed	13·5 knots
Brake horse-power for this speed	4,000

Exhaustive tests were carried out at the National Physical Laboratory Model Tank at Teddington both in regard to the lines of the hull and the most suitable propeller for the form of hull, and from the data obtained by these tests the final form of hull was decided upon (Fig. 1).

The vessels are subdivided by 15 transverse bulkheads into the following compartments, counting from aft: after-peak, motor-room, cross-bunker, coffer-dam, 3 cargo tanks, pump-room, 2 cargo tanks, pump-room, 2 cargo tanks, forward coffer-dam, forehold, and forepeak.

The cargo tanks are further subdivided by 2 longitudinal bulkheads, making a total of 21 cargo oil compartments, each cargo tank consisting of 3 compartments abreast, the centre one being 37% of the breadth of the vessel. This arrangement permits of the best distribution of weights in partly loaded or ballast conditions, and also for the best distribution of the steelwork to obtain the maximum strength.

strength calculations prepared for these vessels were based on the following assumed conditions of the vessel: (1) in still water; (2) in trough of a wave; (3) on the crest of a wave.

The curves showing the calculated bending moments under the above conditions are shown in Figs. 2, 3, and 4, while the strength calculations on which these curves are based are shown in Fig. 5. This latter figure shows the

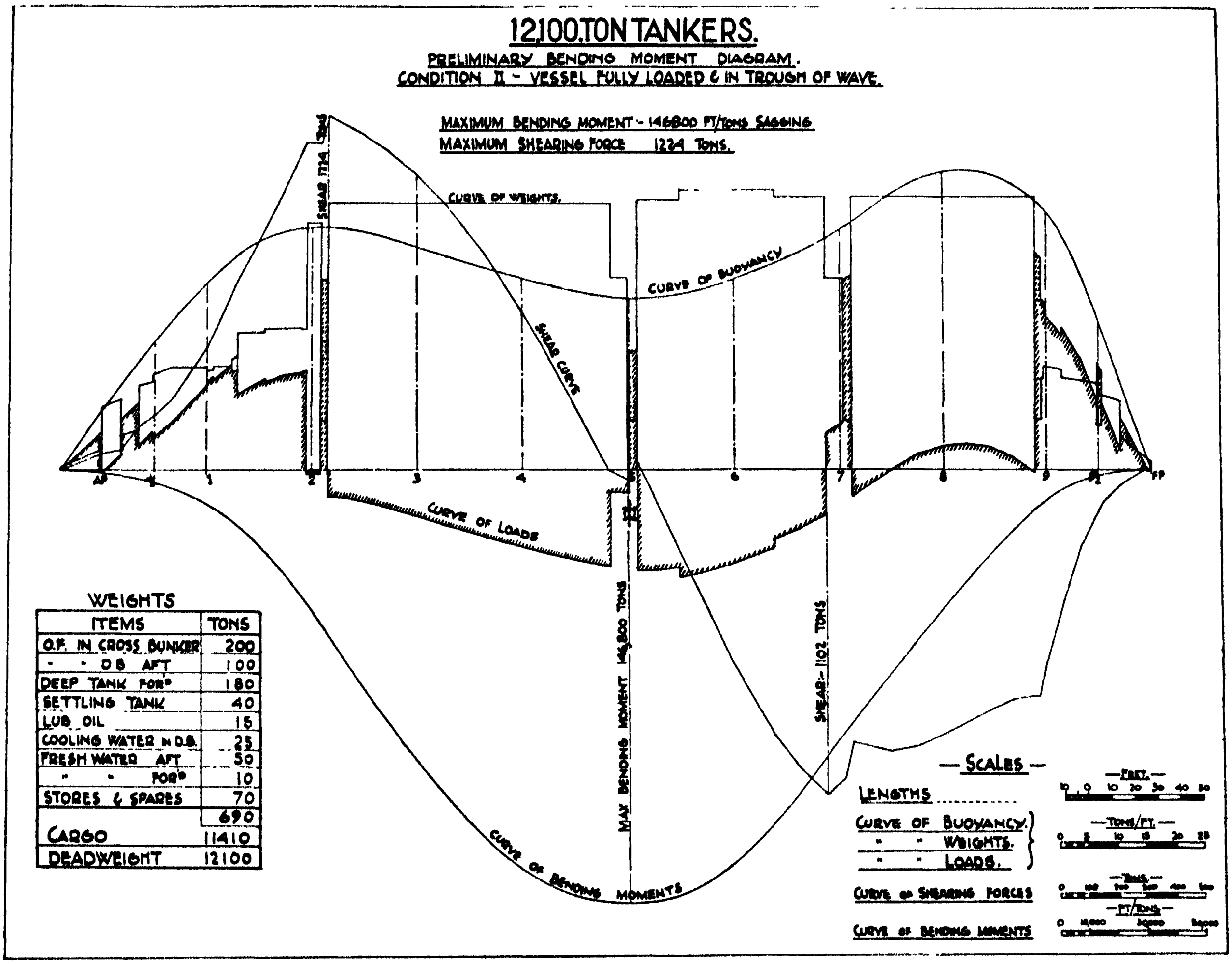


FIG. 3.

The provision of two pump-rooms, each extending the full width of the vessel and each fitted with two cargo pumps, together with the specially arranged pipelines, provides for safe separation between the various groups of tanks and permits of 4 different grades of oil being simultaneously loaded or discharged without risk of contamination.

The steelwork of the hull in way of the oil compartments is constructed on a combined transverse and longitudinal system of framing. The framing in the centre tanks on the bottom and under the decks is arranged longitudinally, with deep transverse, while the side tank framing is arranged transversely with 2 web stringers and 1 web frame in each tank. The transverse and longitudinal bulkheads also have vertical stiffening with web stringers in line with those on the shell plating. Clear of the oil compartments, the ordinary transverse system of framing is used.

The greatest stress to which a tank vessel is subjected develops when the vessel is in a sagging condition, and

calculations involved to ensure that no parts of the vessel are overstrained. Extreme conditions of hogging and sagging when fully loaded are assumed for this purpose as well as for the condition in still water.

The tables show the sectional areas of all strength members, their distance from the neutral axis, the products of the sectional areas, and their distance from the assumed neutral axis, &c. The position of the neutral axis in hogging condition above the assumed axis is found by the formula:

$$\text{N.A. below assumed axis} = \frac{AY_2 - AY_1}{A_T},$$

where AY_1 and AY_2 = the product of the sectional areas and their distances above and below the assumed neutral axis respectively, and

A_T = total sectional areas.

A similar procedure is followed in the sagging condition.

Conditions 1, 2, and 3 are then calculated to ascertain

the stresses at deck and keel equivalent to the flanges of a girder. For this purpose the formula $S = MY/I$ is used, where:

S = stress (compressive or tensile) in tons, per sq. in.,
M = maximum bending moment
I = moment of inertia.

It will be seen from these calculations that the maximum tensile stress at the deck is limited to 6 tons and the compressive stress to 5·6 tons, and that the corresponding stresses in the keel are even less.

Condition 1 shows a bending-moment diagram for the vessel fully loaded and floating in still water. The ideal would be for the curves of weights and buoyancy to coincide, but this, of course, is unattainable with a steel vessel of this form. The curve of weights is compiled from the mean weight of the hull and cargo per foot of length, calculated and set up as ordinates at convenient distances apart. The rectangles on the curve represent local weights such as machinery, superstructures, bunkers, &c.

The curve of buoyancy is compiled from the vessel's displacement, also in tons per foot length and set up in a similar manner to the ordinates of the weight curve. It will be seen that in this still-water condition the weight of the vessel and her cargo are very well supported over almost the entire length by the buoyancy or upward pressure of the surrounding water. The curve of loads which is obtained from the differences between the curves of weight and buoyancy is low over almost the entire length of the vessel.

From the curve of shearing stresses which is compiled from the curve of loads it will be noted that the greatest stresses are directly opposite the points of maximum support in the case of these tankers, the buoyancy being provided by the empty coffer-dams and pump-rooms. Attention might here be drawn to the fact that the condition of a loaded tanker in still water tends towards sagging. This tendency is very slight in these vessels, as will be seen by referring to Fig. 2, condition 1, which gives a compressive stress in the deck of 0·70 ton per sq. in. and a tensile stress in the keel of 0·58 ton per sq. in..

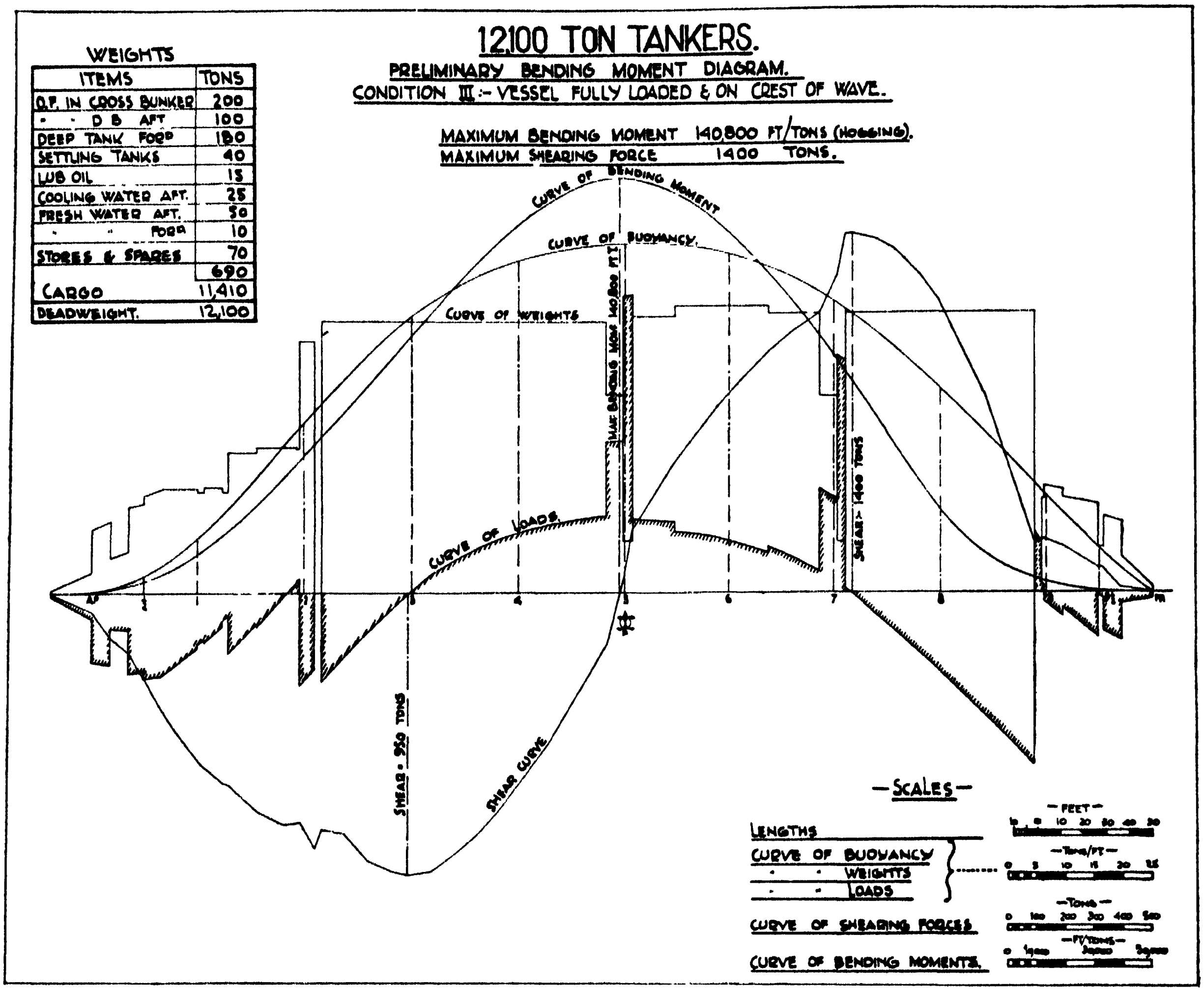


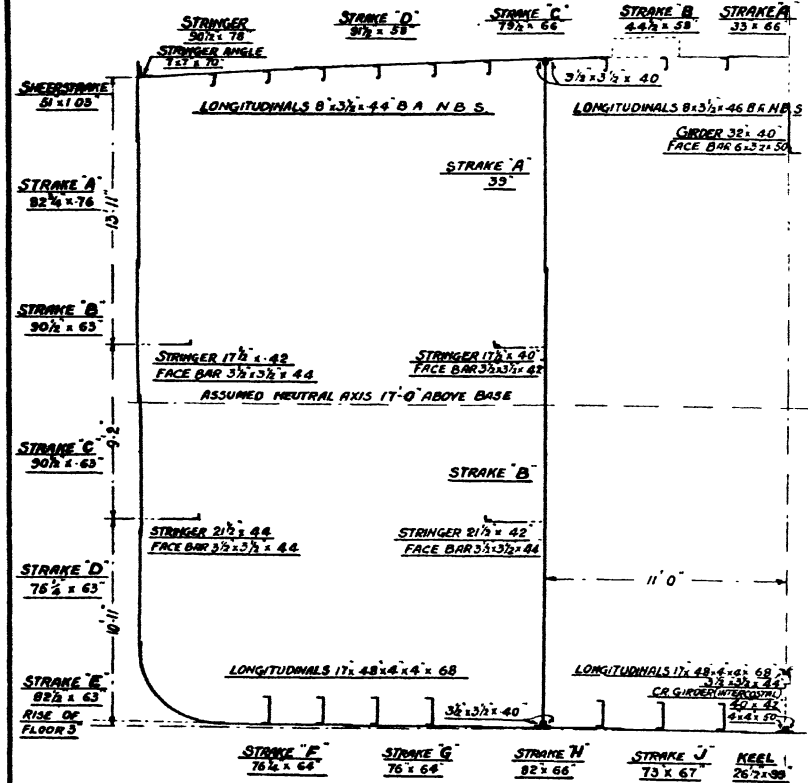
FIG. 4.

When the vessel encounters heavy weather the condition alters entirely.

The figures for conditions 2 and 3 show bending-moment diagrams in extreme conditions of sagging and hogging respectively. The curves of weights are, of course, identical to the still-water condition. The curves of buoyancy have the same areas in all three conditions, as the displacement is taken as being the same throughout. Here the similarity ends, the buoyancy curve is altered in form owing to the altered support to the hull afforded by the wave formation; the points of maximum shear are altered for the same

12,100 TON TANKERS.

460'-0" (B.P.) x 59'-0" (M^LD) x 34'-0" (M^LD).



ITEMS ABOVE NEUTRAL AXIS (ASSUMED 17'-0 ABOVE BASE)

ITEMS	SCANTLINGS	AREA IN SQ INS	Y	AY	AY²	½AH²
DECK PLATING A	33 x 66	21 78	18 25'	397 49	7254	
B	44½ x 58	25 81	18 16'	468·45	9502	
C	79½ x 66"	52 47	18 00'	944·46	17000	
D	91½ x 58"	53 07	17 70'	939 34	16626	
STRINGER	90½ x 78"	70 59	17 20'	1214 15	20883	
DECK ℄ GIRDER	½(32 x 40)	6 40	14 55'	93 12	1355	7 49
LONG^L B^HD A	134 x 39	52 26	12 50'	653 25	8166	536·58
B	87 x 43"	37 41	3 65'	136 55	498	161·61
SHEER STRAKE	51 x 103"	52 53	15 65'	822 09	12866	79·06
SIDE PLATING A	82¾ x 76	62 89	10 52'	661 60	6960	249·51
B	90½ x 63"	57·02	3 75'	213 83	802	267 28
C	5" x 63"	3 15	0·20'	0 63	0·13	
SHELL STRINGER	17½ x 42"	7 35	3 05'	22 42	68	
LONG^L B^HD STRINGER	17½ x 40"	7 00	3·05'	21 35	65	
DECK LONG^LS	6(8" x 3½ x 44")	34 02	17 25'	586·85	10123	
DECK LONG^LS	3(8" x 3½ x 46")	17 58	17 85'	313·80	5601	
DECK STRINGER BAR	7" x 7" x 70	9 31	17 10'	159·20	2722	
LONG^L B^HD BARS	2(3½ x 3½ x 40)	5 28	17 90'	94·51	1692	
D^K C^R GIRDER FACE BAR	½(6 x 3½ x 50)	2·25	13·30'	29·93	398	
SHELL STRINGER FACE BAR	3½ x 3½ x 44	2 89	3 15'	9 10	29	
B^HD D^O	3½ x 3½ x 42	2 76	3 15'	8·69	27	
					121637	1302
					1302	
ITEMS IN SAGGING		583 82		7790·81	122939	
LESS 1/7 FOR RIVETS		83·40		1112 97	17563	
ITEMS IN HOGGING		500 42		6677 84	105376	

ITEMS BELOW NEUTRAL AXIS.

ITEMS	SCANTLINGS	AREA IN SQ INS	Y	AY	AY²	½AH²
SHELL PLATING C	86" x ·63	54 18	3 60'	195 05	702	227 60
D	75¼ x 63"	47 41	9 87'	467 94	4619	156 81
E	82½ x 63	51 98	15 60	810·89	12650	40 32
F	76½ x 64"	48 80	16·82	820·82	13806	
G	76" x 64	48·64	16 87	820·56	13843	
H	82 x 66"	54 12	16·90'	914 63	15457	
J	73 x 67"	48 91	17 00	831 47	14135	
KEEL PLATE	26½ x 99"	26 24	17 20'	451 33	7763	
LONGL B^HD B	202¼ x 43"	87 08	8 45	735 83	6218	2072 58
SHELL STRINGER	21½ x ·44"	9 46	6 10'	57 71	352	
B^HD STRINGER	21½ x 42"	9 03	6 10'	55 08	346	
℄ GIRDER TOP ANGLE	3½ x 3½ x ·44"	2 89	13·75	39·74	546	
BOTTOM LONG^LS	7(17" x ·48 x 4 x 4 x 68)	91 28	16·20	1478·74	23956	
KEEL ANGLES.	4" x 4" x 50"	3 75	16 90'	63 38	1071	
LONG^L B^HD BARS	2(3½ x 3½ x 40")	5 28	16·77'	88 55	1485	
SHELL STRINGER FACE BAR	3½ x 3½ x 44	2 89	6·00	17 34	104	
B^HD D^O	3½ x 3½ x ·44	2 89	6·00'	17 34	104	
					117157	2497
					2497	
		594 83		7866 40	119654	
LESS 1/7 FOR RIVETS		84 97		1123·77	17093	
ITEMS IN SAGGING		509 86		6742 63	102561	
℄ GIRDER	½(40 x 42")	8 40	15 30	128 52	1966	7
					7	
		594 83		7866 40	119654	
ITEMS IN HOGGING		603 23		7994·92	121627	

— HOGGING. —

AREA — 500 42 + 603 23 = 1103 65 SQ INS

N.A BELOW ASSUMED AXIS $\frac{7994·92 - 6677·84}{1103\ 65}$ = 1 19'

I ABOUT ASSUMED AXIS 105376 + 121627 = 227003 □" x FT²

I ABOUT N.A. — 227003 − (1103·65 x 1 19²) =

FOR ONE SIDE = 225436

FOR BOTH SIDES = 450872

Y TO KEEL 15·81'

Y TO DECK AT LONG^L B^HD. 19 25'

— SAGGING. —

AREA 583 82 + 509 86 1093 68 SQ INS

N.A. ABOVE ASSUMED AXIS = $\frac{7790·81 - 6742·63}{1093\ 68}$ = 0·96'

I ABOUT ASSUMED AXIS — 122939 + 102561 = 225500 □" x FT²

I ABOUT N.A. — 225500 − (1093 68 x 0 96²) =

FOR ONE SIDE 224494

FOR BOTH SIDES 448988

Y TO KEEL :— 17 96'

Y TO DECK AT LONG^L B^HD 17·10'

CONDITION Nº1.

VESSEL FULLY LOADED AND IN STILL WATER

MAX BENDING MOMENT. 16 500 FT TONS (HOGGING)

STRESS AT KEEL $\frac{MY}{I} = \frac{16500 \times 15\ 81}{450872}$ = ·58 TONS/□" (TENSION)

STRESS AT DECK $\frac{MY}{I}$ $\frac{16500 \times 19\ 25}{4508\ 72}$ = ·70 TONS/□" (COMPRESSION)

CONDITION Nº2.

VESSEL FULLY LOADED AND IN TROUGH OF WAVE

MAXIMUM BENDING MOMENT 146 800 FT. TONS (SAGGING)

STRESS AT KEEL $\frac{MY}{I} = \frac{146\ 800 \times 17\ 96}{448988}$ = 5·87 TONS □" (TENSION)

STRESS AT DECK $\frac{MY}{I}$ $\frac{146800 \times 17\ 10}{448988}$ = 5·59 TONS □" (COMPRESS^N)

CONDITION Nº3.

VESSEL FULLY LOADED AND ON CREST OF WAVE

MAXIMUM BENDING MOMENT — 140,800 FT TONS (HOGGING.)

STRESS AT KEEL · $\frac{MY}{I} = \frac{140800 \times 15·81}{450872}$ = 4 94 TONS □" (COMPRESS^N)

STRESS AT DECK · $\frac{MY}{I} = \frac{140800 \times 19\ 25}{450872}$ = 6·01 TONS □" (TENSION)

FIG. 5.

reason. The maximum bending moments are, of course, increased very considerably.

When it is considered that these two conditions are the most extreme likely to be met with at sea, in the one case the vessel being supported by the ends and in the other case being supported amidships, the stresses in the keel and deck are very reasonable. Figs. 6 and 7 show the midship section drawing which indicates the disposition of the steelwork and the general arrangement in regard to the layout of the oil tanks, machinery spaces, accommodation, &c.

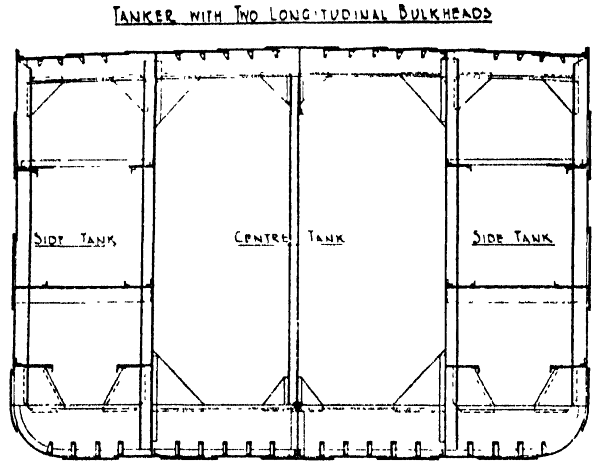


FIG. 6.

The utilization of exhaust gases for the generation of steam in an auxiliary boiler for the purpose of driving essential auxiliary machinery such as steering-gear, steam-driven dynamo, refrigerators, accommodation heating, &c., is one of the modern improvements in the Diesel-propelled vessel which has been embodied in the design of the vessel under review. All auxiliaries such as cooling water, lubricating oil, fuel oil, and bilge pumps are of the rotary type, direct driven by means of chain gearing and clutches from the main engines (Fig. 8) so that it is only for the auxiliary machinery enumerated in the previous paragraph for which steam is required.

Should it be necessary to generate additional steam for such purposes as heating of heavy viscous cargo or for use on the deck auxiliaries such as when entering or leaving port, the boilers are so arranged that one or more furnaces can be working on exhaust gas heat while the others are operating on the usual oil-fuel burners, as each furnace, combustion chamber and smoke-box has its own individual uptake and funnel, and there is thus no interference between the two methods.

The steering-gear is one which deserves mention in that a new method has been introduced. It is of the hydraulic

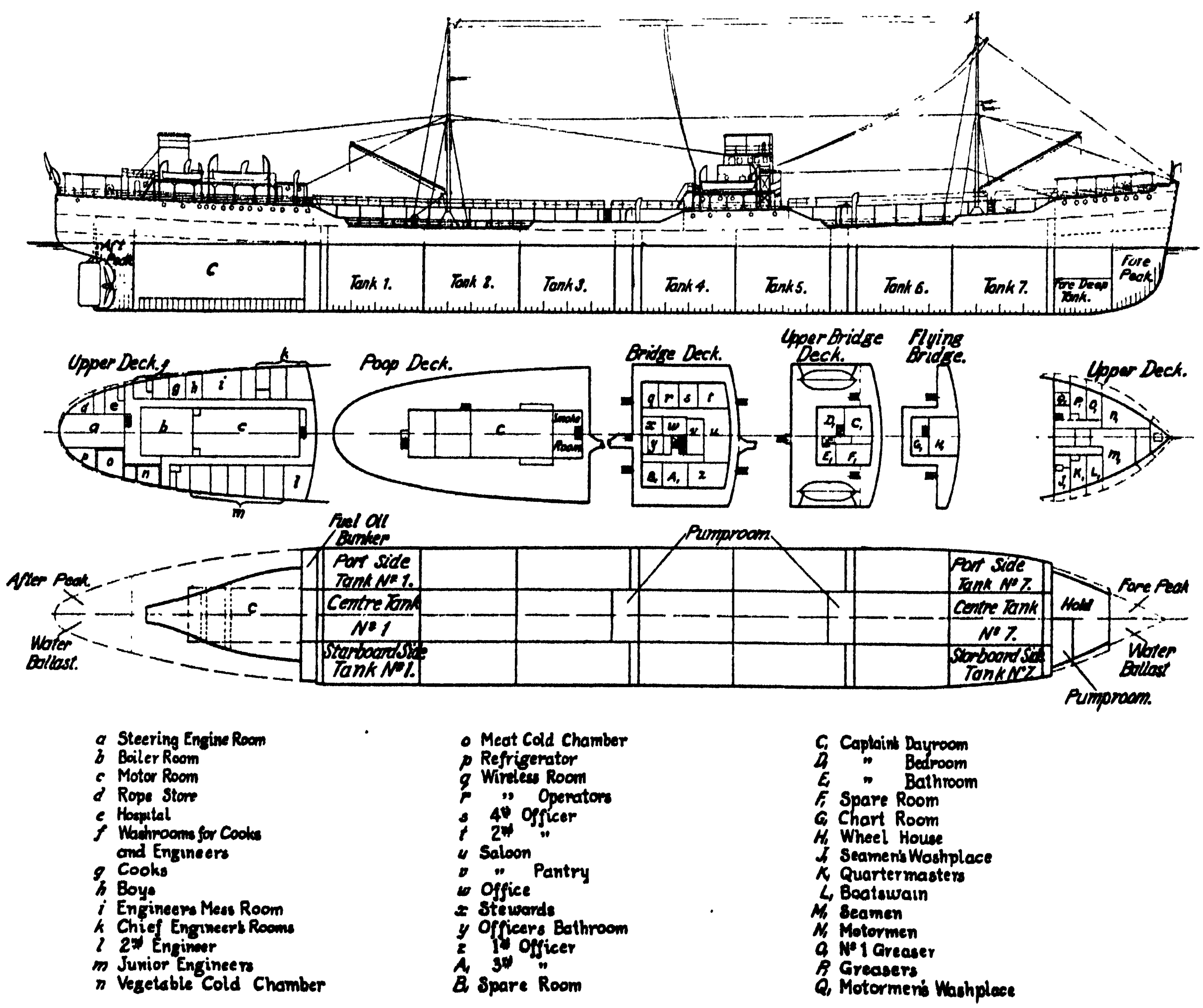


FIG. 7.

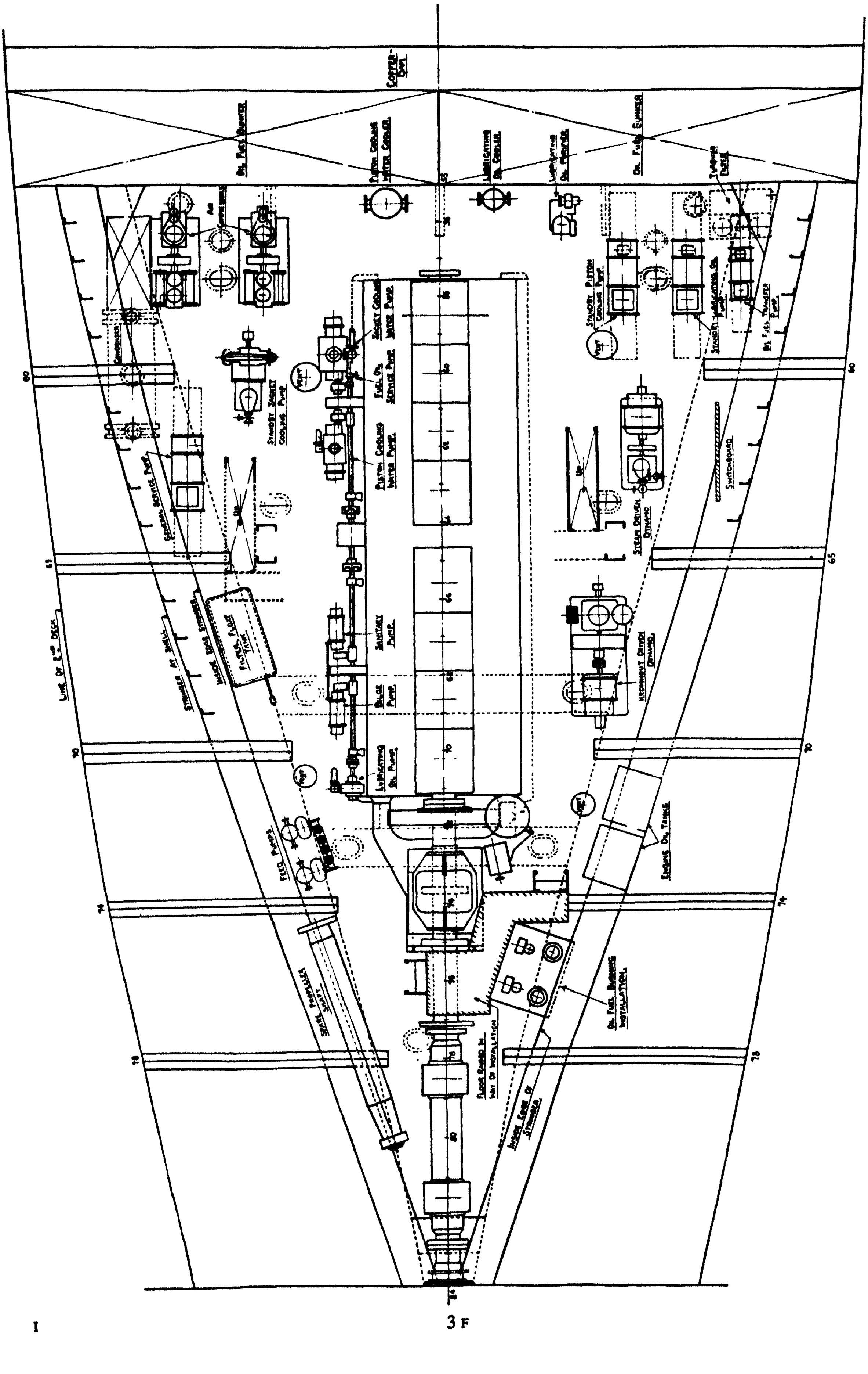


FIG. 8.

type with a Hele-Shaw rotary pump, but instead of this pump being driven by means of an electric motor in accordance with the usual practice, it is driven by a special steam engine, which, when the gear is in mid-position, merely idles over the centres, but which, as soon as the quarter-master turns the steering-wheel in either direction, picks up its revolutions and power in an as efficient and economical a manner as did the electric motor.

Apart from the reasons which have been enumerated above in regard to the general adoption of the Diesel engine for tankers, it must be borne in mind that the tanker differs materially from other types of cargo vessels in regard to the length of time in port, either loading or discharging; and port regulations to be complied with for safety which do not admit of any overhauling or repair work to be carried out while the vessel is loading or discharging.

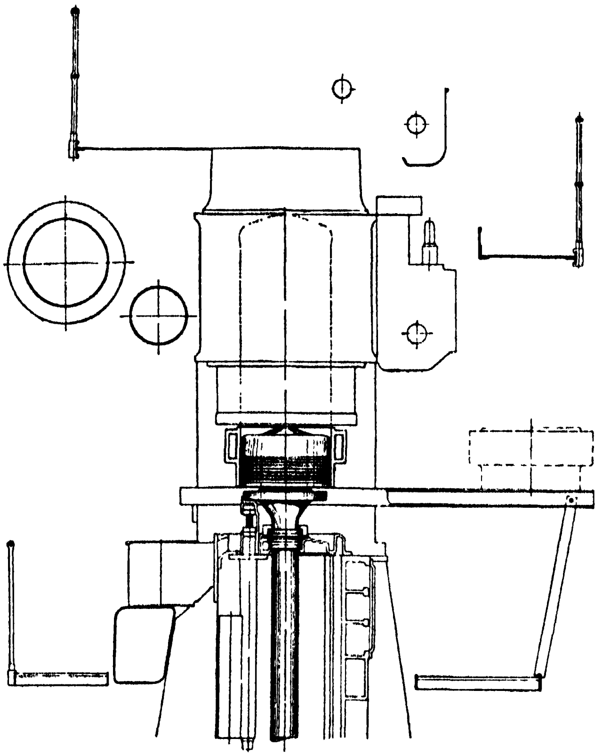


FIG. 10.

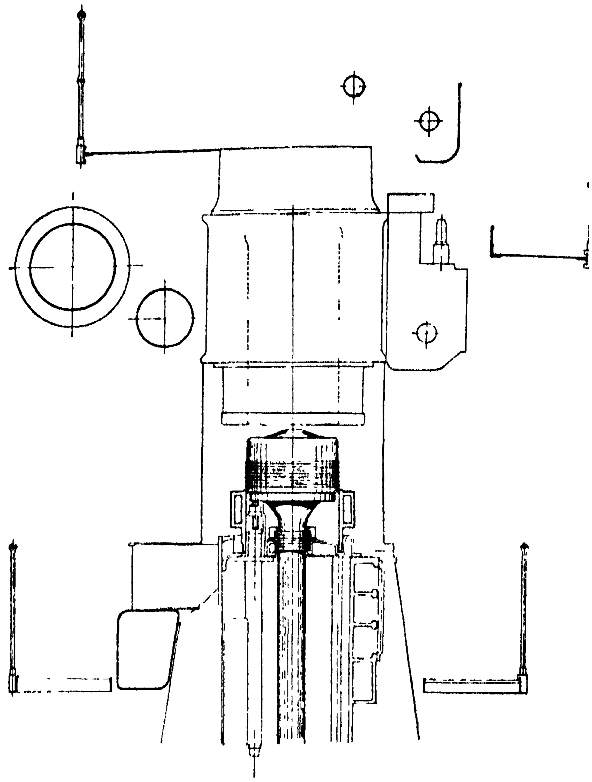


FIG. 11.

Whereas a general cargo vessel may spend anything from a week to a fortnight at its terminal ports, the tanker is 'turned round' again in anything between 24 to 48 hours. This leaves very little time for overhauling and adjusting the parts, so that it is of the utmost importance that apart from its economic aspect, it shall be absolutely reliable and so designed that any overhauling or adjustments required can be done in a minimum amount of time.

The main engine of the vessel described herein is an 8-cylinder, single-acting, 4-stroke cycle engine, working with supercharge and capable of developing 4,000 B.H.P. for a trial speed of 13 knots. One of its principal features is the accessibility of the pistons, which can be exposed for examination and removal, if necessary, of the piston rings and/or pistons, and a series of photographs, Fig. 9, and diagrams showing the methods employed are reproduced.

It will be seen that the casing by means of which the lower part of the cylinder is closed in for the purpose of forming the supercharge air pump is first removed and the engine placed on the bottom centre (1st picture). The cylinder skirt is then unbolted from the bottom of the cylinder and lowered, exposing the pistons and rings, and the rings can be removed, if desired, over the top of the piston (2nd picture). If it is desired to remove the pistons, the bolts by which it is secured to the piston rod are removed while the engine is as shown in the first picture. A special travelling rack is erected in position and the skirt unbolted and lowered on to the traveller (3rd picture) and drawn out clear of the cylinder beam, where the skirt can be lifted clear of the piston (4th picture). Figs. 10 and 11 illustrate this in diagrammatic form.

Finally, there is the question of the propellers. Much more attention is being given to this important item than has been the case in the past. Propellers were then designed merely on data gathered from results obtained from the log-books of existing vessels, and considering these in conjunction with the lines of the hull, revolutions of the engine, &c. Research work has been carried out at the experimental tanks, and the question of suitable propellers for the proposed form of hull, together with stream-lined rudders, contra-flow blades, fins, and other devices, whereby full advantage is taken of the water stream-lines closing in around the stern of the vessel, has been thoroughly investigated.

As a result of such tests, a propeller having four blades, 15 ft. 6 in. diameter, 11 ft. pitch, with an expanded surface area of 75–8 sq. ft., was adopted for the vessel under review.

The latest devices to assist and ensure safe navigation, such as wireless direction finders, echo sounding machines, in addition to the usual equipment of deep-sea sounding machines, &c., have been installed, so that the vessel may be considered to be representative of the most up-to-date tanker practice.

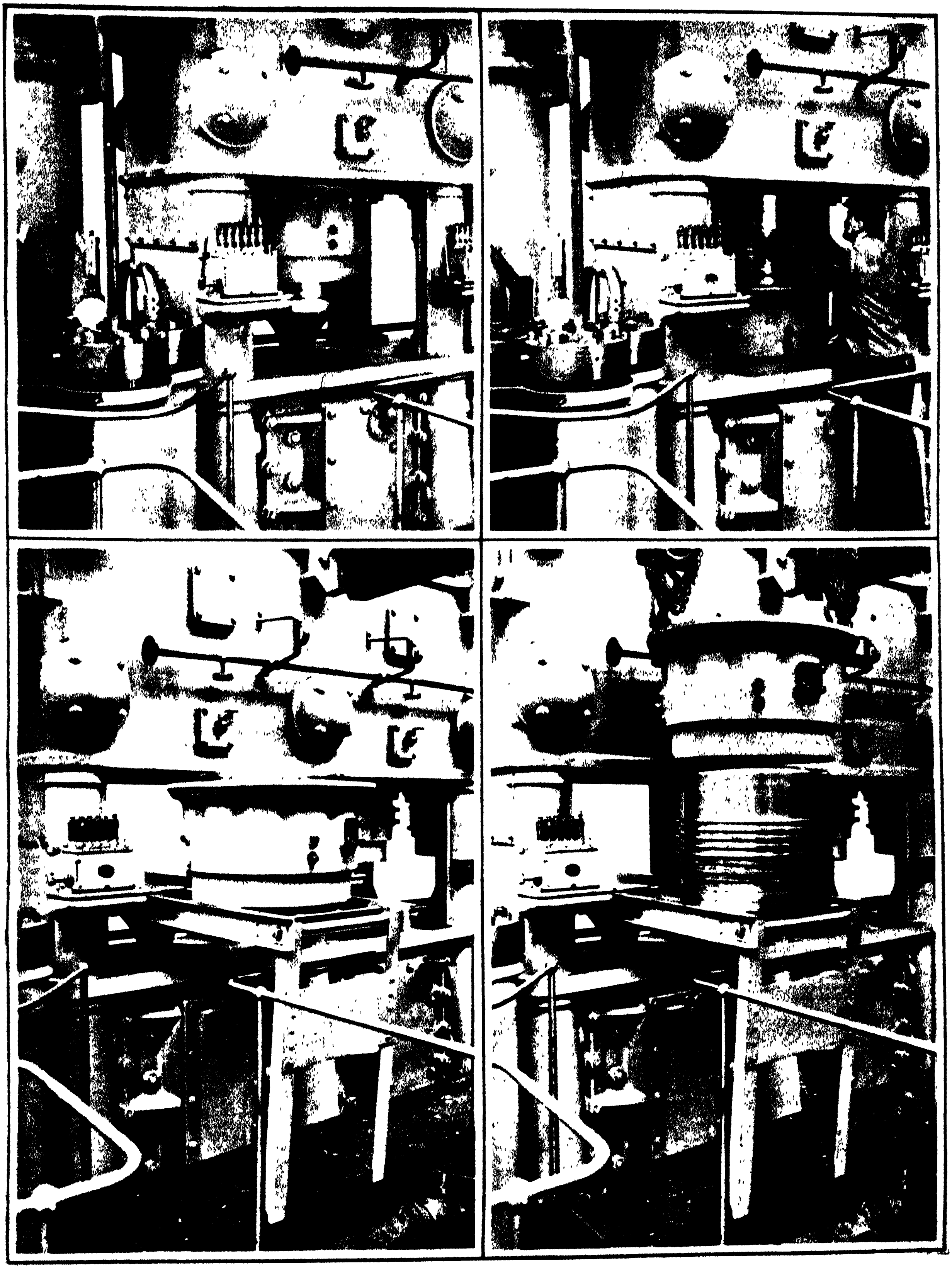


Fig. 9

SECTION 16

NATURAL GAS TRANSPORT

NATURAL GAS TRANSPORTATION

By STANLEY LEARNED, B.S.

Assistant Chief Engineer, Phillips Petroleum Company

THE utilization of natural gas for domestic and industrial consumption at points a great distance from gas-producing fields has called for the construction—particularly in the past few years in the United States—of thousands of miles of large diameter gas pipelines. The factors affecting natural gas transmission will be considered in the order mentioned:

1. Flow of gas in pipelines.
2. Compression of natural gas.
3. General factors affecting economic design of pipeline systems.
4. Gas pipeline construction.
5. Economic design of pipeline system.

Flow of Gas in Pipelines

For natural gas transmission, the most accurate and the commonly accepted formula for calculation of gas flow is the Weymouth formula (see *Trans. of the American Society of Mechanical Engineers*, **34**, 1091–1104, 1912), which is:

$$Q = \frac{853{\cdot}5\, D^{2{\cdot}667}\sqrt{P_1^2 - P_2^2}}{\sqrt{L}},$$

in which

Q = quantity in cubic feet a day at the following conditions:
base pressure 14·65 lb. abs. (4 oz. above atmosphere),
base temperature, 60° F., specific gravity of gas 0·65,
flowing temperature, 40° F;
D = actual internal diameter of pipe in inches;
L = length of line from points of pressure determination in miles;
P_1 = upstream pressure, pounds per square inch absolute pressure;
P_2 = downstream pressure, pounds per square inch absolute pressure.

Because of the fractional exponent and the number of variables, the use of a nomograph for solution of this formula is a great time-saver. An example is shown on the nomograph marked 'Alignment Chart for Solution of Weymouth Formula of Gas Flow'. The accuracy of solution by this method exceeds accuracy of the assumed variables.

The formula given above and the alinement chart attached are for gas flowing at 40° F. and for a specific

Flowing Temperature in Degrees F.

Specific gravity	*40*	*50*	*60*	*70*
0·60	1·04	1·03	1·02	1·01
0·65	1·00	0·99	0·98	0·97
0·70	0·96	0·95	0·94	0·93
0·75	0·93	0·92	0·91	0·90
0·80	0·90	0·89	0·88	0·87
0·85	0·87	0·86	0·85	0·84
0·90	0·85	0·84	0·83	0·82
0·95	0·83	0·82	0·81	0·80
1·00	0·81	0·80	0·79	0·78

gravity of 0·65 (air = 1·0). Table A shows values of $P_1^2 - P_2^2$. Table B shows values of $D^{8/3}$ for use in solution when not using the nomograph. The flow of gas in pipelines varies inversely as the square root of the gravity and of the flowing temperature expressed as degrees absolute. The previous table gives factors by which the results from the alinement chart should be multiplied for different gravities and flowing temperatures.

TABLE A

$P_1^2 - P_2^2$ (in thousands) for use with Alinement Chart of Weymouth's Formula

P_1 *Compressor dis.*	P_2 - *Compressor Intake* *25*	*50*	*75*	*100*	*125*	*150*	*175*	*200*
50	2·6							
75	6·4	3·8						
100	11·5	8·9	5·1					
125	17·9	15·3	11·4	6·3				
150	25·5	22·9	19·0	13·9	7·6			
175	34·3	31·7	27·9	22·8	16·4	8·8		
200	44·4	41·8	38·0	32·9	26·5	18·9	10·1	
225	55·8	53·2	49·3	44·2	37·9	30·3	21·4	11·3
250	68·4	65·7	61·9	56·8	50·5	42·9	34·0	23·9
275	82·2	79·6	75·8	70·7	64·3	56·7	47·9	37·8
300	97·3	94·7	90·9	85·8	79·4	71·8	63·0	52·9
325	113·6	110·5	107·2	102·1	95·8	88·2	79·3	69·2
350	131·2	128·6	124·8	119·7	113·4	105·8	96·9	86·8
375	150·1	147·5	143·6	138·5	132·2	124·6	115·8	105·7
400	170·2	167·6	163·7	158·6	152·3	144·7	135·9	125·8

Weymouth's formula is based on the assumption that the gas follows Boyle's law. Gases compress to a smaller volume at high pressures than Boyle's law would indicate. Although in most practical problems corrections are not necessary, the formula which follows can be used in those cases where pressures are high enough to require correction. John C. Diehl [4, 1927] recommends a correction based on formula:

$$B = \frac{0{\cdot}154P(M+4e+3c+0{\cdot}22a)}{1{,}000},$$

where

B = deviation in per cent.,
P = gauge pressure in lb. per sq. in.,
M = per cent. of methane,
e = per cent. of ethane,
c = per cent. of carbon dioxide,
a = per cent. of air.

[Note: No correction needed for nitrogen.]

Inasmuch as some gas-lines are operating with average flowing pressures of 450 lb., this variation materially affects capacity. With a gas of 81% methane, 8% ethane, 1% carbon dioxide, and 10% nitrogen, this deviation would be

$$B = \frac{0{\cdot}154(450)[81+4(8)+3(1)]}{1{,}000} = 8{\cdot}04\%.$$

In addition to the calculations on single lines of uniform size, one is confronted with:

1. Single lines of varied diameter.
2. Looped lines of varied diameter.

ALIGNMENT CHART FOR SOLUTION OF WEYMOUTH'S FORMULA OF GAS FLOW

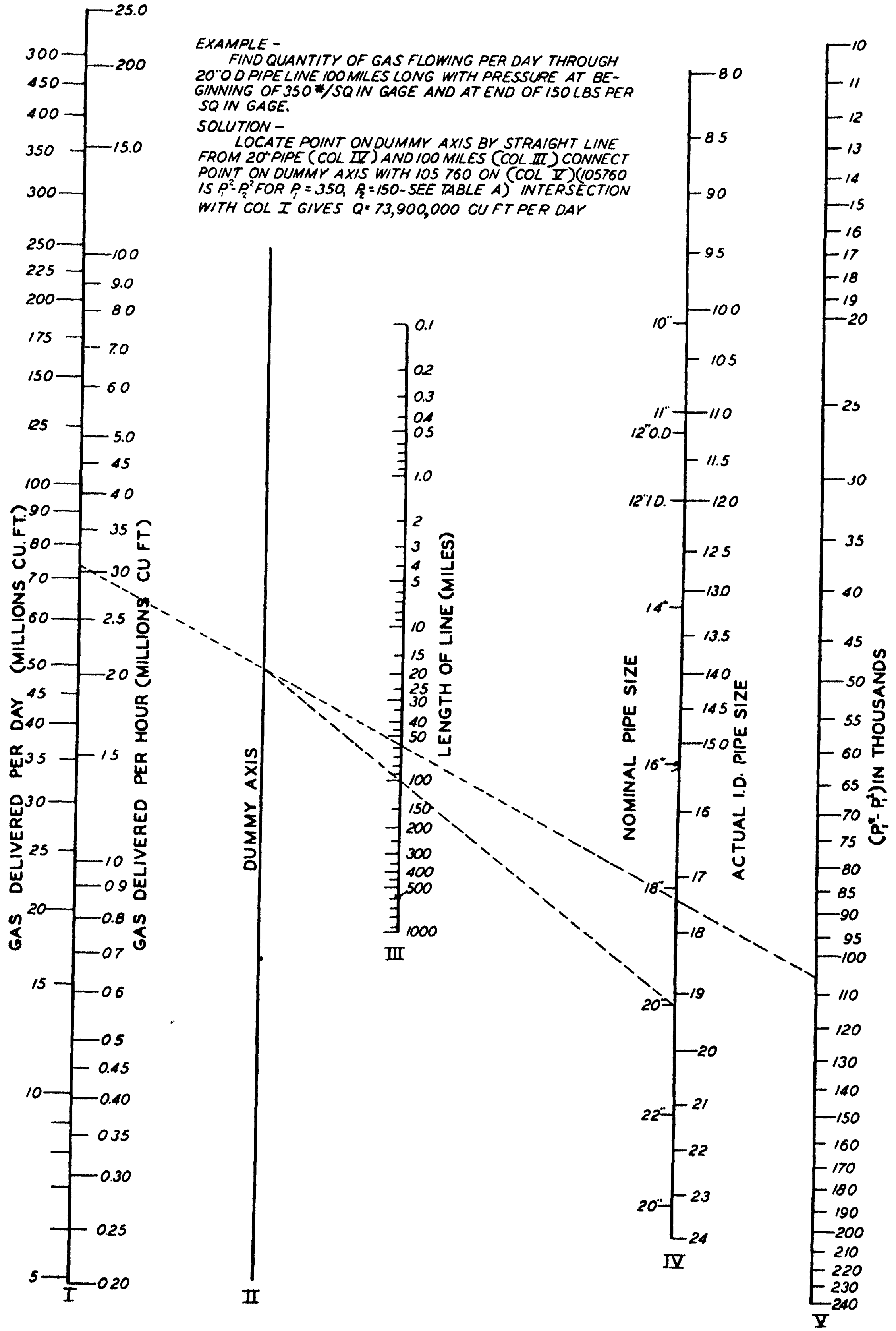


FIG. 1.

To solve for pressure drop in single lines of varied diameter, all lengths must be transposed into an equivalent length of some one chosen diameter, by formula:

$$L_1^1 \quad L_1\left(\frac{D_0}{D_1}\right)^{16/3}, \ L_2^1 = L_2\left(\frac{D_0}{D_2}\right)^{16/3},$$

where

L_1^1 = equivalent length of pipe of D_0 diameter,
L_1 = length of diameter D_1,
D_1 = actual diameter of section of pipe considered,
D_0 = actual diameter of chosen size,

and L_2^1, L_2, and D_2 are equivalent for another section of pipe. The length to be used in Weymouth's formula becomes the summation of $L_1^1, L_2^1, \ldots\ldots, L_n^1$.

greater even than the adiabatic formula by from 10 to 20%. The alinement chart marked 'Alignment Chart for Determining Horsepower Required for Single Stage and Two Stage Compression' gives results close to actual experience. It follows, quite closely, results from any one of the three commonly accepted compression horse-power curves (i.e. Weymouth, Biddison, Pacific Coast Gas Association) (Fig. 2).

Analysis of the alinement chart shows that where horsepower per million feet of gas exceeds 100, two-stage compression is desirable, requiring less engine horse-power. This occurs at a point slightly above a compression ratio of 5, ratio of absolute discharge to absolute suction pressure.

The horse-power required to compress natural gas depends on neither the value of the discharge nor suction pressure, but on the ratio of these two pressures. It takes as much power to compress gas from 10 lb. gauge to 108 lb. gauge as to compress gas from 108 lb. gauge to approximately 600 lb. gauge, yet the work performed at the pressures in the latter case will deliver 5 times as much gas as at suction pressure of 10 lb. and discharge of 108 lb.

This fact is taken advantage of on long-distance transmission lines with a large number of compressor stations by boosting gas to design pressure at the initial station on the line, and holding suction pressure of succeeding stations sufficiently high that ratios of compression are between 2 and $2\frac{1}{2}$ and locating the compressor stations accordingly.

TABLE B

Values of $D^{8/3}$

Actual I.D. of pipe in inches	*Size of pipe in tenths of inches* 0	1	2	3	4	5	6	7	8	9
1	0·000	1·271	1·626	2·013	2·453	2·948	3·502	4·117	4·794	5·538
2	6·349	7·232	8·187	9·218	10·33	11·51	12·78	14·14	15·57	17·10
3	18·72	20·43	22·24	24·14	26·14	28·24	30·44	32·75	35·16	37·68
4	40·30	43·06	45·92	48·90	51·98	55·20	58·53	61·98	65·56	69·27
5	73·10	77·07	81·16	85·40	89·75	94·26	98·90	103·7	108·6	113·1
6	118·9	124·2	129·7	135·4	141·2	147·2	153·3	159·5	166·0	172·6
7	179·3	186·2	193·3	200·5	207·9	215·5	223·3	231·2	239·3	247·6
8	256·0	264·6	273·4	282·4	291·6	300·9	310·5	320·2	330·1	340·2
9	350·5	360·9	371·6	382·5	393·6	404·8	416·3	427·9	439·8	451·9
10	464·1	476·6	489·3	502·2	515·3	528·7	542·2	556·0	569·9	584·1
11	598·5	613·1	627·9	643·0	658·3	673·8	689·5	705 5	722·0	738·2
12	754·8	771·7	788·8	806·1	823·7	841·6	859·6	877·9	896·5	915·4
13	934·3	953·6	973·1	993·0	1013	1033	1054	1075	1096	1117
14	1138	1160	1182	1204	1227	1250	1273	1296	1320	1344
15	1368	1393	1418	1443	1468	1493	1519	1545	1572	1599
16	1626	1653	1680	1708	1736	1764	1793	1822	1851	1881
17	1911	1941	1971	2002	2033	2064	2096	2128	2160	2194
18	2226	2259	2292	2326	2360	2594	2429	2464	2499	2534
19	2570	2606	2643	2680	2718	2754	2793	2831	2869	2908
20	2947	2987	3027	3067	3107	3148	3189	3230	3272	3314
21	3357	3400	3443	3486	3530	3574	3619	3664	3709	3754
22	3800	3846	3893	3940	3987	4035	4083	4151	4179	4229
23	4279	4329	4379	4429	4480	4531	4583	4635	4687	4739
24	4792	4846	4900	4954	5008	5063	5119	5175	5231	5287
25	5344	5401	5458	5517	5576	5635	5694	5753	5812	5872
26	5933	5994	6056	6118	6180	6242	6305	6368	6432	6496
27	6561	6627	6692	6757	6823	6890	6957	7025	7093	7161
28	7230	7299	7368	7438	7508	7579	7650	7721	7793	7866
29	7939	8012	8085	8159	8234	8309	8384	8460	8536	8612
30	8689									

In looped systems of various lengths and diameters, all sections must be transformed to an equivalent diameter of a section of pipe L_0 in length by formula:

$$D_1 = D\left(\frac{L_0}{L}\right)^{3/16},$$

where

D_1 = equivalent diameter of pipe L_0 in length,
D = diameter of pipe L in length.

Then equivalent total diameter D_0 of all sections is $D = (\sum D^{8/3})^{3/8}$. Capacity is then obtained by using L_0 and D_0 in Weymouth's formula.

Compression of Natural Gas

If gas could be compressed isothermally, or in accordance with the adiabatic law, specific formulae could be given for the horse-power required for compression. Due, however, to mechanical losses, compressor cylinder clearances, &c., the horse-power required for compression is

General Factors affecting Economic Design of Pipeline Systems

The construction of any natural gas system is dependent on:

1. Suitable and sufficient market for a period of years.

ALIGNMENT CHART FOR DETERMINING HORSEPOWER REQUIRED FOR SINGLE STAGE AND TWO STAGE COMPRESSION

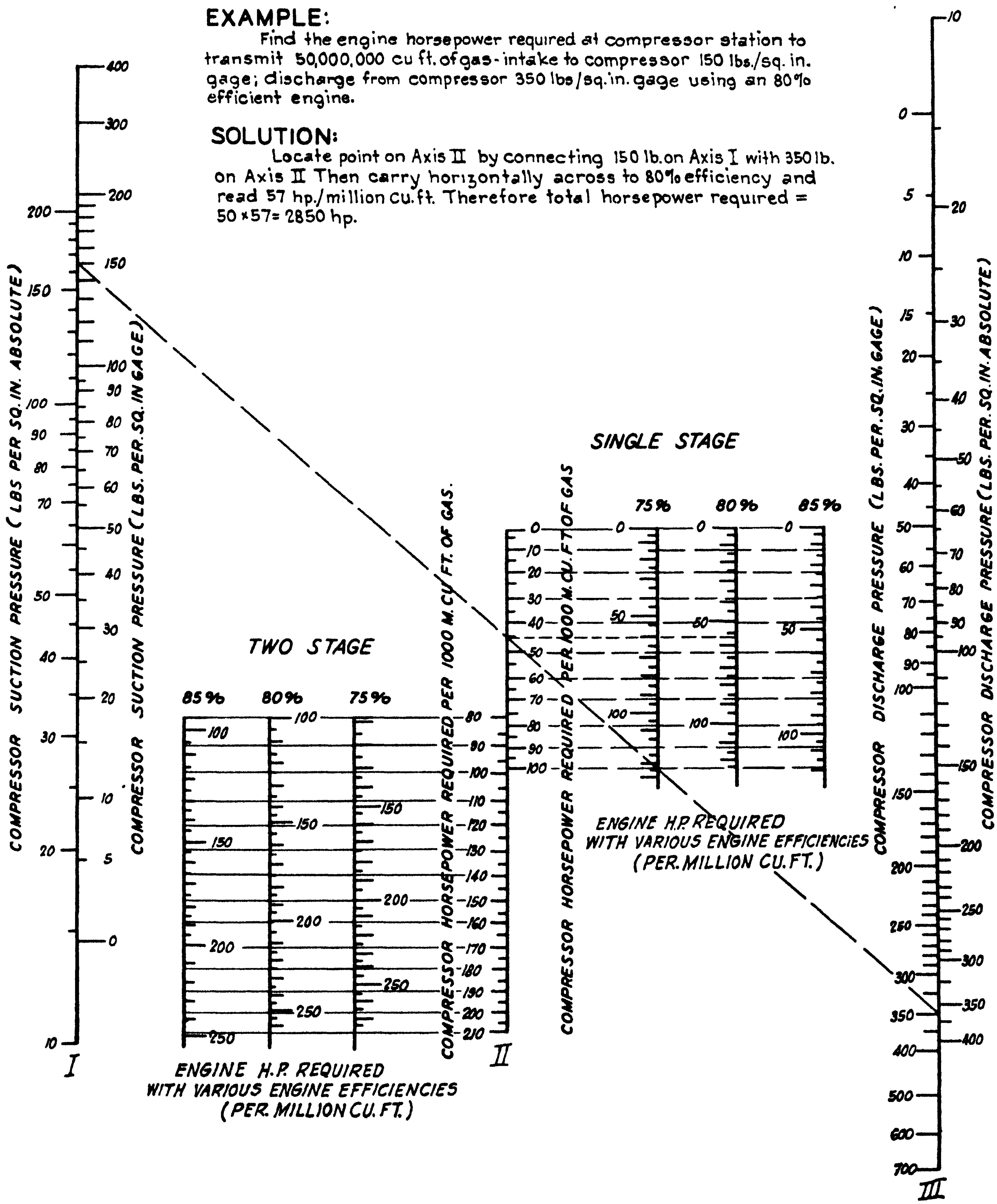


Fig. 2.

2. Ample reserves of natural gas.
3. Ample finances.

Consideration of the first two items is necessary before a pipeline system can be designed.

Natural Gas Market.

The potential market is the first factor to consider in the design of natural gas transmission systems. In the early natural gas lines the load was almost entirely for domestic lighting. The domestic load is now for cooking, water heating, and house heating. This type of consumption has a low load factor. The load factor may vary considerably by reason of: (1) rate structure, (2) weather conditions, (3) percentage of heating load to total load, &c. However, some figures prepared by the Dallas, Texas, Gas Company, covering a period of years, will show their actual variations in consumption (from Diehl, *Natural Gas Handbook*):

Analysis of Domestic Sales over Six Years Period, 1921–6, showing Average Sales per Meter (1,000 B.Th.U. Gas)

	Total	*Cooking only*	*Hot water only*	*Space heating only*
January	13,015	2,800	550	9,665
February	11,190	2,530	515	8,145
March	9,260	2,800	550	5,910
April	7,160	2,800	340	4,020
May	3,900	2,800	225	875
June	2,780	2,555	225	..
July	2,280	2,055	225	..
August	1,950	1,725	225	..
September	2,130	1,905	225	..
October	2,960	2,620	340	..
November	6,235	2,800	550	2,885
December	8,850	2,800	550	5,500
Total	71,710	30,190	4,520	37,000
Average monthly load	5,976	2,516	377	3,084
Load factor—aver. % of max.	45·8	89·5	68·8	32·0

When the peak days within the large demand month are considered, the average domestic consumption load factor will not exceed 40%.

In the preliminary design of gas systems, care must be given in estimating domestic business not only to the proper consideration of load factor, but to the amount of the load. It may be said:

1. Domestic cooking and water-heating load are about the same regardless of climate, but may be affected by rate at which gas is sold.

2. House-heating load will vary for climatic conditions and the price of gas. The domestic gas heating load per meter will be about 16 cu. ft. per day per degree deficiency below 65° F. Data on temperatures for any community are available from the U.S. Weather Bureau. To explain, let us assume an average temperature for November of a community of 50° F., then the estimated gas heating demand for the month will be $(65°-50°)\times 30$ (days of month) $\times$ 16 cu. ft. = 7,200 cu. ft. Where gas heating rates are close to those of competitive fuels, nearly all of the house-heating load is obtainable. Where rates for natural gas will be materially above those of competing fuels, only a small portion of this load will be available. The probable total maximum number of meters to be installed is often estimated from population statistics, but is probably better taken from present telephone and light outlets.

The domestic load is a comparatively small portion of most of the larger gas transmission lines recently constructed. None of the large lines constructed in recent years would have been possible without large industrial loads. These large industrial loads have made possible the construction of larger diameter lines and a material increase in load factor. Industrial gas consumers are continuous operating plants such as steel mills, oil refineries, smelters, power plants, &c., where the load factor may easily average 85% or better. Analysis of competing fuel prices and adaptability must be considered on industrial loads. The typical operating conditions of the industrial concerns to be served should be studied in order to arrive at probable load factor on industrial business. Rate structures which will penalize low load factors are desirable.

In calculating total gas to be handled in the pipeline system, allowance must be made for fuel for compressor stations and for line loss.

The capacity of a gas-line varies as the 8/3 power of the diameter, while the cost varies almost directly as the diameter. The value of industrial loads which will require large diameter pipelines is apparent.

Reserves of Natural Gas.

Almost all gas transmission lines are projected on long life pay-outs of the original investment. Gas reserves sufficiently large to assure gas for the life of proposed projects are necessary before they can be financed.

Several methods for estimation of gas reserves are in use, depending on data available, and include:

1. Production decline curves.
2. Saturation method.
3. Decline in rock pressure.
4. Decline in open flow capacity.

In producing gas fields, quite often a combination of several methods is used as a check. The saturation method is most commonly used for estimation of this nature on whole fields. Formula may be stated as follows:

$$R = 1{,}170A\times t\times p\times s\times RP,$$

where

R = recoverable gas in cubic feet at a pressure of 8 oz. above atmosphere,
A = estimated area of gasfield in acres,
t = estimated average thickness of gas sand in feet,
p = percentage of porosity of sand,
s = percentage of saturation of sand (usually considered 100%),
RP = rock-pressure.

In the preparation of this formula it is assumed that only 40% of the gas will be actually utilized, the balance being wasted or unrecovered due to low-pressure conditions.

Gas Pipeline Construction

Pipe and Pipe Joints.

The many thousands of miles of large diameter gas pipelines which have been constructed in the United States in the past few years would not have been possible without developments in the mill manufacture of pipe and in the type of field joint.

It is only in very recent years that large diameter seam-

FIG. 3 Line-up welding. Finished line-up weld of three joints ready to be assembled over ditch

FIG. 4. Pipe ready to be lowered into ditch

FIG. 5 Pipeline paper machine in action. Hot application cold tar or asphalt materials are applied to the pipe, followed by paper wrapping

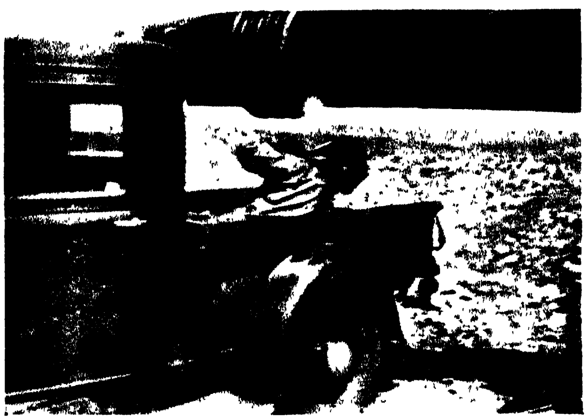


FIG. 6 Welding expansion joint in overhead river crossing

Fig. 7

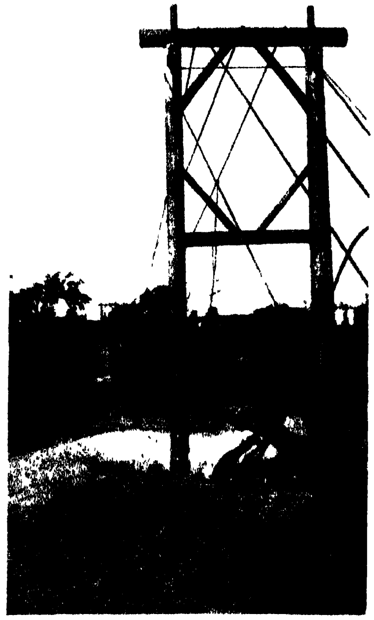


Fig. 8

Fig. 9

Figs 7–9. Finished overhead river crossings of different types

less and electric-welded line pipes have been available. These types of pipes have allowed for high working pressures due to higher tensile-strength steel which can be used in their manufacture.

The development of pipe joints is probably more important than the pipe itself. The improvement in welding technique, both coated rod electric and high-speed acetylene, has made welding of large lines possible without throwing undue stresses into the pipe by reason of the heat of welding. Many miles of solid welded large diameter gas-lines have been laid (Fig. 3). Many more miles of partially welded and partially Dresser or Dayton coupled lines have been laid (Fig. 4). The solid welded line is not only cheaper in first cost, but occasions less leakage.

The leakage of gas is a very important item. Practically all new large gas transmission lines are tested by the pressure-drop method as reported in the U.S. Bureau of Mines Report of Investigations, no. 2752, before acceptance and use. In order to have a common base of comparison, leakage is usually expressed as 'thousands of cubic feet annually per mile of 3-in. line at 100 lb. per sq. in. gauge pressure'. Allowable leakage varies from 10,000 cu. ft. per year to 100,000 cu. ft. per year per mile of 3-in. pipe at 100 lb. gauge pressure.

The development in the past several years of thinner wall pipe suitable for field handling has made possible the use of larger diameter pipes at lower pressures economically. Pipe as thin as 8 gauge (0·165 in.) in sizes as large as 24 in. has been laid in commercial practice. The use of thin wall pipe materially decreases laying costs.

Protection against Corrosion.

Intensive studies on the protection of pipelines against corrosion are bearing fruit in two ways:

1. Methods to predetermine corrosiveness of soils.
2. Methods to protect against corrosion.

Because it is extremely expensive to uncover, raise, and recondition a large diameter pipeline after it has been materially affected by corrosion, most of the large lines laid in recent years have been coated in their entirety as a protection against corrosion, which corrosion would probably affect only a small portion of the system (Fig. 5). This has been a necessary but a decidedly uneconomic practice.

Studies on corrosion, its detection, and its relation to soil resistivity have developed data which no longer makes such procedure necessary. Sheperd's rods are used to measure resistivity, and in general no coatings are required where resistivity is not below 800. Interpretation of such data in the light of knowledge of soil and drainage conditions is advisable.

After the corrosive areas are determined, coatings of hot coal tars or asphalts are applied and the whole covered with asbestos felt or concrete as a protection.

Surveys.

The general location of any line is, of course, determined by the source of the gas and the location of its market, and the knowledge that the most economical line is a straight line between the gas-supply and gas market. With the general route selected in this manner, with the assistance of soil maps and such other data as may be available, an aerial reconnaissance is desirable. From this a definite route can be selected and an aerial photograph of the route made.

Aerial photographs have been used on most of the more recent large gas-lines, because they:

1. Allow a quicker preliminary survey.
2. Allow the immediate purchase of right of way for the laying of the line.
3. Lower the cost of right of way because the map can be used to show the owner the exact location of the proposed line in relation to his developments, and also because no survey party has served an advance notice of the intention to lay a line.
4. Shorten actual length of finished line because the best methods of avoiding obstruction can be worked out from the complete survey rather than as the survey party reaches them.

Usually such aerial maps are made to cover strips of from 1 to 3 miles wide and at scales of from 5 in. to 10 in. per mile. Scales of at least 6 in. per mile are desirable.

River Crossings.

Inasmuch as a large gas pipe will float in water, it is necessary either to lay overhead crossings on bridges or lay smaller lines in the bed of the streams with river clamps placed intermittently on the pipe, both to strengthen the joint and to add weight to overcome the buoyant action of the water. Practice on this point is divided by reason of (1) personal opinion, (2) types of rivers and comparative costs of the several methods. An individual analysis of each stream is required (Figs. 6, 7, 8, and 9).

Economic Design of Pipeline System

Only with a complete knowledge of the projected load of a proposed gas pipeline system can the best and most economic design for any project be determined. Inasmuch as the ultimate loads in most cases can be only roughly estimated, it quite often happens that what was designed originally as the best system proves to be an expensive one. In general, however, one can, by following the fundamentals, determine the most economical pipeline and compressor system with any specific set of conditions. A few of these fundamentals are:

1. **Pipe.** Analysis of flow of gas through lines and the required thickness of pipe leads to the conclusion that larger size pipes with lower pressures will effect the cheapest cost. For any pipeline size there is a minimum thickness of pipe which can be laid. With this pipe thickness known it follows, then, that the size of line should be selected which will best handle the required quantity of gas and stress the steel in the pipe on the discharge side of compressor stations to its allowable value.

2. **Compression Ratio.** The compression ratio should be held low as was explained under gas compression. At the initial station, the pressure is brought up to a value which will stress the pipeline to its allowable value. Intermediate compressor stations are located as the market demands in such a manner that the compression ratio will not exceed 2 to 2½ for best results.

With these two fundamentals established, it is a question of trial solutions to determine the most satisfactory arrangement of compressor stations and pipeline size, taking into consideration the cost of laying pipe, installing compressor stations, and the operation of these facilities. Some writers have suggested formulae and curves, but the writer feels that each individual line requires its own analysis as to cost of installation and operation.

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SECTION 17

STORAGE OF OIL AND GAS

CRUDE GATHERING SYSTEMS

By C. A. ANDREWS

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AN oilfield gathering system comprises the plant, equipment, and pipelines required to transfer crude oil from the casing-head to the crude disposal tanks. On fields where gas is produced provision has to be made for the separation and, in many cases the collection, of such gas. The organization, operation, and control of the entire system is, as a general rule, under the charge of a Field Production Department, of which the conveyance of crude from the casing-head to the disposal tanks is a major care.

Plant and Equipment

The characteristics and type of plant and equipment chosen in any individual case is almost entirely dependent upon the particular natural and industrial conditions existing in that area. Obviously, the primary factor determining the selection of suitable plant is the quality and quantity of crude produced. For instance, the crude may be 'sweet' or 'sour' (of relatively high sulphur or hydrogen sulphide content), with greater or less gas/oil ratio, of high or low viscosity, contain water, &c. In order to cope with the problems introduced in the different circumstances, various changes or modifications have to be adopted, but, on the whole, the system will comprise gas separators, well-head or area flow-tanks, area pumping installations, and crude disposal tanks, all with the relevant pipelines, fittings, and instruments. During the life of the field changing reservoir conditions necessitate innovations or alterations and, almost without exception, at some time or other arrangements have to be made for crude dehydration.

The equipping of a lease will also be influenced to some extent by the topography, inasmuch as plant or pipeline details may be qualified by considerations of relative surface elevations.

The greater part of the machine plant on an oilfield consists of prime movers and pumps of low or medium capacity together with boilers and auxiliaries as well as compressors where gas is produced. By virtue of the heavy duties performed and the rough conditions under which it is often expected to work it must be sturdy, suitable for rapid renewal and re-erection, possess a high degree of accessibility and a reserve of power and adaptability for diverse modifications of service. The general tendency in design is, in consequence, the adoption of the latest metallurgical improvements with a view to increasing strength, reliability, and simplicity, if possible with a reduction in weight. This progress is changing, in many ways, plant incidental to gathering systems.

The variety of prime movers is wide and includes those operated by steam, gas, gasoline, or oil as well as electricity, choice being made according to circumstances. Steam is usually generated in portable boilers, of which very efficient oilfield types can be obtained, but on account of costs of operating, maintaining, and fuel and water servicing its use is at a disadvantage where scattered small producers have to be worked.

When field exploitation has reached the stage where a gathering system is functioning, fuel in a form suitable for use in gas, gasoline, or oil engines is almost certain to be available, so plant of this type is very generally used [10, 1935].

Capital and maintenance costs involved when either steam- or internal-combustion engines are used are increased by the necessity of service auxiliaries such as fuel lines and those requisite for the obtaining of water, its treatment by filtering, settling, or softening, to which it may have to be subjected before it is in a fit state for use in either boilers or in cooling circuits [22, 1935]. Fuel in the form of crude or gas is perhaps available, although before it can be utilized service pumps or compressors, together with the associated pipelines for distribution, will be necessary. Where electric power can be purchased from a utility company in the vicinity [21, 1935], expenditure and trouble can be saved by the use of electric motors. Even if such a source of supply is not available, improvements in design leading to enhanced life and reliability of flame, weather, and explosion-proof motors and control apparatus is leading to continual increase in their use on oilfields with attendant advantages to be derived from the presence of one central power station instead of several scattered plants consisting, in part, of prime movers.

In the event of conditions being such that several pumping units, either permanent or transportable, have to be installed, each for the purpose of transferring crude from a well to an area flow-tank station, servicing with electric power may have many advantages in comparison with other methods [3, 1935; 11, 1935]. These might include rapidity and simplicity of connexion to the power source, great increase in the facilities for distant control, convenience for the use of intermittent starting and stopping devices and lower operating and maintenance costs. The efficiency with which direct and intermittent control of electrically powered pumps can be exercised has been amply demonstrated on many fields where declining or low initial crude production requires evacuation from the wellhead flow tank at stated times for definite periods during the day.

Lease pumps of reciprocating types include direct coupled and belt- or chain-driven varieties; centrifugal pumps, single- or multi-stage, are invariably direct coupled. In common with the power plant, pumps should be of rugged build, be qualified to meet strenuous conditions, and have a fair resiliency so far as load duty is concerned.

Mobility of pumping plant is a characteristic of oilfield exploitation, and as capital expended on foundations has no salvage value there is an increasing demand for portable combination units comprising prime mover and pump, both mounted on a rigid structural steel framework which at the same time serves as a skid [16, 1935]. For light duty these merely rest on a firm levelled grade, but for heavier work they are superimposed on wooden blocks or a grillage which may be sunk into the ground. Naturally, for central or area pumps which may be permanently located, and from which a high duty is demanded, concrete foundations are provided.

Pumps should be fitted with automatic sight-feed lubricators, the requisite valves, and pressure gauges on

suction and discharge lines. The addition of a strainer on the suction and, where a valve might be closed against a pump, a pressure-relief valve should be provided in the discharge line in a situation where overflow of oil can be cleanly dealt with. All centrifugal pumps should be fitted with non-return valves on the discharge side in order that counter-rotation shall not occur in the event of stoppage of the prime mover and back pressure in the discharge line permitting reversal of fluid flow.

The pumping of crude holding gas in solution is simplified by maintaining a pressure on the suction side in excess of the vapour pressure of the fluid. Special precautions are taken in the design of centrifugal pumps for this duty in order that in no part of the pump a sub-pressure is likely to occur. Gas vented through pet-cocks attached to the cylinders of reciprocating—or the casing of centrifugal—pumps, should be conducted by tubing to the outside of the pump-house, tun-dishes and drainage lines being provided to take care of the inevitable fluid carry-over. Buildings housing crude-oil pumps should be well ventilated, with fan ventilators if necessary, particularly where there is a possibility that sour gas may contaminate the atmosphere.

For plant, running, and maintenance record books are essential and items of plant should be assessed a working period of duration in accordance with advice given by the maker or experience of local conditions. At the end of this time they should be removed from service for general inspection and overhaul.

All pipe connexions and fittings should be as simple as will meet the case, especially if these consist in part of manifolds. The lay-out should be made with a view to reducing loss of head due to flow friction, e.g. bends or even long bends being substituted for elbows. As in tank stations, identification of lines and valves by means of labels or coloured paint aids considerably in the efficient control of operation.

Lay-out

In order to save plant and other expenses by centralization of gauge and flow tanks, pumps, flow-instruments, controls, &c., lay-out and organization should be such that groups of wells in a field can be connected and operated as producing areas, the culminating point of collection in each area being a flow tank or pump installation as the case may be. From these installations main feeders carry crude to the disposal tanks.

From a consideration of the number of varying factors inherent in the practice of crude collection it follows that the gathering system of each area has to be designed to suit local conditions and that a standard system cannot be devised. Nevertheless, there are two essentials governing the lay-out of a system on any oilfield. They are: (*a*) in order to conserve reservoir energy, the minimum possible amount of back pressure shall be imposed on a well by surface equipment, and (*b*) economy and simplicity of surface operation shall be aided by taking advantage of topographical features in order to move crude under the influence of gravity flow.

In general, connexions and fittings between the wellhead and the separator or flow tank, whichever may be the first vessel into which the crude is conveyed, are designed to eliminate unnecessary back pressure. If this is not the case, adjustments to attain this end should not be difficult to accomplish, and, in the interest of the field, should be effected as soon as may be convenient.

Even where conditions are such that rapid handling of the oil necessitates the use of pumps, lines laid as if for gravity flow will assist in economies in pumping expenditure. The question of the design of the lay-out to include the maximum advantages to be derived from gravity flow is complicated by the fact that production developments may take place rapidly or cannot always accurately be foreseen, but from the time when the first well on a field is brought on to production, due care should be taken to make separator, tank, and pump locations with a view to the probable position of future wells. If in the course of unanticipated developments full use of the topography has not been made, the relaying of pipelines or even relocation of pumping installations or tanks may prove worth while. It is of importance to remember that pipelines carrying crude containing gas under gravity flow are liable to become gas-locked. Grading of the lines assists in avoiding this, but at those points where locking is likely to arise, vents should be provided [20, 1935].

When sites are being selected for the installation of separators, dehydrating plants, pump-houses, tanks, &c., consideration must be given to the rapid and safe removal of production waste products. Whatever final method of disposal may be adopted, the first step is usually a gravity one.

Modern production methods insist upon a gathering system in which the crude is kept isolated from the atmosphere to the greatest possible extent. This assures that not only is a greater proportion of the lighter constituents retained in the crude but internal corrosion of tanks and pipelines is reduced, possible chemical interaction between oxygen and the crude is avoided, and fire risks are reduced. Any gas produced with or released from the crude at separators, tanks, &c., is withdrawn by means of a gas-collecting system which may consist of one or more sub-systems, each running at a specified pressure, particularly if stage separation is in operation. This gas-collecting net is usually an integral part of, even if auxiliary to, the crude gathering system and has a definite economic importance as it enables final vapours to be salvaged for processing or direct use.

Wellhead Separators

It is a matter of practical field experience that individual wells and, as a result, the entire field, can be held under better observation and control if a separator is provided for each well.

A separator is placed in the flow line between wellhead and flow tank in order that separation of gas and crude may take place at a previously determined pressure. On leaving the separator the oil should be free of gas at the particular outlet pressure chosen. For high-pressure wells a combination of high-pressure and low-pressure separators are used, one of the objects attained being the smaller containers which are required. A further step is multi-stage separation, a recent development of considerable practical and economic value in which banks of separators, adjusted to four or five pressure stages in descending order, are used with beneficial results to the light hydrocarbon content of the crude as delivered to the flow tank [8, 1936; 9, 1935]. Conversely, the sum total of light hydrocarbons such as propane, butane, and pentane in the gas is reduced, but as the gas removed at higher pressures has a negligible content of such hydrocarbons it can be utilized for pipeline use direct from the high-pressure stage, so reducing the volume of gas to be treated for gasoline recovery or other process.

The realization of the importance of reducing back

pressure has in recent years led to considerable modifications in the design of Christmas trees or wellhead hook-ups and lines connecting these with wellhead separators. All fittings are such as to cause the minimum energy loss, bends instead of elbows, gate-valves instead of globe-valves, &c. A corresponding advance has been made in the design of separators, which are now constructed in a manner which ensures that during the passage of the crude any pressure loss is kept as low as possible. In consequence, the rough types of a few years ago are giving place to scientifically designed units with which may be incorporated centrifugal entrance connexions, deflecting plates, fluid-gas level float control, mist extractor, pressure gauge, sight-level gauge, pressure-relief valve, &c., as aids to efficient separation.

Separators are invariably of cylindrical form and the well conditions such as pressure, rate of flow, and gas/oil ratio will determine the size and type required as well as whether it shall be placed horizontally or vertically. A crude of low specific gravity produced with a high gas/oil ratio will require more efficient separation than a heavier crude with a low ratio. A well producing with a high gas/oil ratio will deliver to a separator a flowing mass of fluid largely composed of foam, which must be thoroughly broken down. The greater the intensity of foaming action the longer is the period required for phase separation. It is questionable whether the breaking of foam from all types of crude can be effected by violent contact with baffles or similar devices; these may perpetuate or intensify the foam. Furthermore, pressure head is lost and a higher percentage of the volatile hydrocarbons is removed with the gas. Recognition of this fact has caused investigation, and the design of separators for foam-producing wells has been modified to allow longer flow periods as well as less violent flow, factors which have the additional advantage of reducing entrainment of crude with the gas with consequent simplification of the gas-collecting system. Where such a system exists final separation may not take place at atmospheric pressure. Both oil and gas leave the separator at pressure, usually a few inches of water, such that the gas can be carried to a flare-point. The small quantity of gas carried forward in the oil is then vented to atmosphere at the flow-tank vent lines.

Gas-oil separators are not expected to function as water-traps when water is being produced with the crude. Clean oil is conveyed to the flow-tanks whilst water-oil mixtures or emulsions usually are treated before reaching these tanks. Accordingly, the location of the separators can with advantage be such that the oil can flow under the influence of gravity to the flow tanks or dehydrating plant as the case may be. In order to achieve this object, separators are often built upon sub-structures of height sufficient to give an additional few feet of head.

Flow Tanks

For the purpose of gathering crude produced from individual wells, or groups of wells in different areas, flow tanks are used, the size of which is dependent upon that part of the field production which they are intended to gather. In general they do not serve as storage tanks, but function more in the nature of balance tanks for intermediary pumping units. Inasmuch as it is invariably necessary to gauge the crude production of a well at definite periods, it is customary to provide two tanks so manifolded that one can be filled and gauged whilst the other is emptying. Where it can conveniently be arranged, crude from two or more wells is run into one flow tank or flow-tank station, provision being made by manifolding for gauging the production from any one well.

Changing field conditions demand a type of tank which can be erected and dismantled as occasion may require: consequently tanks of small capacities are used, e.g. holding from 65 bbl. to 500 bbl.; in exceptional cases up to 2,500 bbl. The desired flexibility, both as regards tank capacity and removal from site to site, is attained by the use of bolted steel tanks with standardized interchangeable plates. These are erected with ease and rapidity by supervised unskilled labour and are supplied complete with special spanners, joint-packing strips, cut gaskets, or jointing for supplied fittings, jointing compounds, &c. When properly erected, bolted tanks are gas-tight, but where a vapour-collecting system is in operation they should not be expected to withstand a pressure of more than 2 oz. or ½-oz. vacuum. Riveted or welded tanks do not find general use.

Although of small dimensions, the grades for these tanks should be constructed with care. For a bolted tank a firm and level grade is absolutely essential because the effects of slight settling are likely to give rise to more trouble than would be experienced with a riveted or welded tank. In the selection and construction of a grade provision for efficient drainage must be made. Great inconvenience may be caused by external corrosion of the tank base-plates either because they may have to be replaced when the tank is required for service or because when dismantled it is found that they are no longer suitable for further use. Consequently a tank site should be located with a view to avoiding deleterious soil conditions.

Base-plates should not contact with soil or unprepared ground; however innoxious such ground may appear, there will almost certainly be present conditions which will accelerate corrosion. The plates, to which anti-corrosive paint has been applied, should be laid on a 3-in. layer of hard stone ballast, of 1 in. ring and less, upon which is superimposed about 2 in. of earth or sand thoroughly mixed with heavy crude or residue. Both layers must be well tamped, the final surface being as level as practically possible.

The use of 'sour' crude or its residues should be avoided, as these will probably aggravate corrosion. One or two ditches of about 6 in. deep by 9 in. wide filled with crushed stone under the ballast layer leading from the tank with an outlet into the firewall drainage-sump will assist considerably in removing extraneous water from the grade.

Where local conditions are such that a stone and oil-sand grade cannot be provided and abnormal corrosion is anticipated, it has become the practice to interpose sheets of coal-tar saturated felt or an asbestos-base paper attached to the plates by means of an application of hot asphalt.

Essential fittings supplied with tanks include manhole and/or clean-out plate, the latter being now preferred on the ground of ease of ingress for inspection and sludge removal, detachable pads for drainage and crude inlet and outlet connexions, external and internal ladders, roof fittings to facilitate gauging either by dipping or a float-level gauge, sample taking, access to the tank, &c. A pressure and vacuum regulating valve should be considered as essential, ample venting area being provided to allow for sudden variations in volume of the gas or crude content. Pads or stools for vapour gathering or heating-coil line connexions have to be added by the tank builders at the time of erection unless especially specified. Whenever

possible, steps for mounting should be provided in lieu of ladders and where tanks are adjacent, non-skid walkways built of interchangeable sections with handrails are found to give added safety as well as being time- and energy-saving for gauging and control purposes.

As in the case with other equipment, special anti-corrosion measures have to be taken where sour oil is produced. The entire inside of the tank should be galvanized, sprayed heavily with aluminium paint or metallized with aluminium in order to enable the steel to resist corrosion. In addition, air should be excluded and equalizing lines installed to permit flow of gas from filling to emptying tanks. Sour crude gases containing hydrogen sulphide are dangerous and should be vented from the tanks with care [19, 1935].

Development of sour oilfields with the consequent difficulties due to excessive corrosion is forcing attention upon wooden stave tanks with water-seal roofs of improved design for use in gathering systems. Since 1934 these have been produced and utilized in increasing numbers and are found to be eminently suitable for the attainment of the objects sought. Success with sour crudes is leading to their adoption on normal crude fields where water-contaminated crude has to be treated, particularly if the water carries salt in solution.

Pipe connexions to the tanks should be orderly and allowance should be made for expansion and contraction in the pipelines due to temperature changes where these are excessive. Forethought on the location and orientation of tanks with regard to possible extension to a flow-tank station will often aid in laying neat, compact, and easily operated manifolds. Safety and efficiency are increased when tanks are clearly numbered and manifold pipelines and valves labelled or otherwise marked for rapid identification. Flow-tank installations should be well supplied with light for night work, flame and explosion-proof electrical fittings being used. With the development of flood-lighting technique this system with its better illumination and enhanced safety is being increasingly adopted.

Water Contamination

Dehydrating plants and method of dehydrating are adequately dealt with in the section devoted to that subject.

On the whole, oil-water combinations as produced from wells can be divided into two groups: (*a*) simple oil-water mixtures from which the water will settle, and (*b*) emulsions of varying intensity and tenacity according to the varying subsurface conditions existing at different wells. This rough classification is by no means rigid: the fluid produced may be in an extreme case an admixture of oil, water, and emulsion.

Apart from affecting the type of dehydration plant chosen, various oil-water conditions in the production from oil-wells affects the gathering system. Clean oil of course can be conveyed direct from the separators to the flow tanks either by pumps or by gravity flow. On the other hand, a water-oil mixture must be dehydrated as soon as possible after its exit from the wellhead separator because any additional turbulence-provoking handling such as pumping may either initiate or aggravate emulsion conditions. Moreover, the more pipelines and plant exposed to such a mixture the greater will be the possibilities for corrosion.

When production consists of a stable emulsion, or crude containing a certain amount of oil-water mixture in this state, settling vessels at each well will not effect elimination of water from the mixture. In such cases either area or central dehydration plants are established where treatment of the production from several wells is performed. These plants are usually operated in conjunction with either area flow-tank or disposal-tank stations; in fact, where the emulsion can be broken by the injection of chemicals from lubricators placed in flow-lines, a flow tank serves as a settling tank.

Drainage-points should be situated so that removal of water takes place at the lowest part of any vessel. If this is done an oil-water interface is always present, and it is here that corrosion will be at its worst.

A gathering system might be influenced by water contamination in various ways, e.g. gravity flow may be arranged to a dehydrating plant, insertion of automatic sight-feed chemical lubricators or oil-water separators between wellhead separators and settling tanks may be necessary or additional pumping installations required.

Disposal of water separated from contaminated crude may become a matter of considerable magnitude. The water is invariably foul and legal restrictions usually prevent water of this nature being discharged without preliminary purification treatment into the nearest drainage channel such as a sewer, stream, or river. Water removed from an oil-production system will most likely carry with it not only a small percentage of oil but also sludge composed of mineral matter such as sand or silt particles, &c., commonly known as bottom settlings. From this mixture the oil is gravity-separated, being retained in traps constructed of wood, concrete, or masonry consisting of 'under and over' baffles through which the waste liquid slowly flows. Trapped oil is skimmed as a rule into a side trough, from whence it is pumped away to salvage. These traps should never be placed in a natural channel such as a stream bed (if this be permitted) without provision being made for flood-water, and should be fitted with sluices for the elimination of silt and sludge from the upstream side.

Oil and bottom settlings, however, are easily handled. Mineral salts in solution in the water give rise to major complications. Very dilute solutions may perhaps be drained into flowing water direct, but those containing a higher percentage of salts have to be disposed of by other means, e.g. soakage or evaporation from artificial ponds created by erecting earth-retaining walls, injection into permeable subsurface strata using disused wells as a medium, or dumb wells especially drilled or sunk to a similar strata [1, 1935; 23]. In all of these cases underground geological conditions should be ascertained in order that the foul water does not reach, either by soakage or injection, a stratum which is a source of oil or potable water.

Gauging and Flow Control

The control and gauging of production is an essential part of the operation of a field. Major control of production is maintained by different means; on flowing wells by regulating pressure on the well-flow string; on air- or gas-lift wells by regulating air or gas-pressure both as regards magnitude and time of application; on pumping wells by adjusting pump conditions. These operations, however, lie outside the scope of a gathering organization which undertakes gauging and flow control after crude has reached the surface.

Gauging is effected in two ways: by direct tank dipping or by the insertion of orifice plates into a flow-line with the accompanying flanges from which pressure tubes are taken to connect with a meter.

The rate of flow of oil from a well is dip-gauged by the

simple process of measuring the depth of oil in a tank with a steel tape, turning crude from the well into the tank for a definite period, then again measuring the depth. The difference between the two readings multiplied by the area of the fluid surface gives the volume of oil produced. In practice, tanks of a capacity exceeding 250 bbl. are 'strapped' because the area of the fluid surface varies from level to level owing to constructional inequalities such as change of tank diameter coincident with change of strake, slight convexities or concavities of the side plates, 'deadwood' variations, &c. [4]. Dip tables are accordingly prepared giving the capacity of each successive inch of level, and from these the capacity between any two levels is ascertained. Where float-level gauges are used the process of determining the quantity of oil in the tank is precisely the same, with the exception that depths are read on the gauge scale.

Indicating, recording, and integrating orifice-flow meters are obtainable which can meet oilfield requirements. Although carefully executed dip gauging gives more precise results, meters possess the great advantage of providing a permanent record of static and differential pressures, and hence the quantity flowing, in a pipeline. They are unsuitable for small wells and are not used on lines subjected to flow such as exists when a well produces spasmodically (i.e. flows by 'heads') or is being pumped intermittently, although they can be utilized in lines from such wells provided steady flow is attained by means of, say, a separator and a flow tank functioning as a surge tank.

Orifice plates must be inserted in straight lengths of pipe where there is an unobstructed flow approach of at least 10 pipe diameters. Should there be a fitting which disturbs flow conditions, e.g. a valve, an elbow, &c., just outside this limit, straightening vanes inserted in the line 5 diameters above the plate will ensure more accurate readings. On the downstream side of the flange an uninterrupted flow of at least 5 diameters must be allowed.

With the aid of a formula dependent upon the diameter of the orifice, the viscosity, and specific gravity of the oil, and the chart reading, the flow quantity can be calculated.

For convenience of operating, where possible flow meters are installed at an area flow-tank station, either on the incoming lines when detailed records are required or on the station discharge line. Final quantitative determination of production at the lease disposal tanks is always performed by dip gauging, due allowance being made for expansion or contraction arising from temperature differences from a normal, usually 60° F.

Sampling of crude takes place concomitant with gauging with the object of maintaining a check on the quality of the oil produced, the presence, quantity, and quality of water, storage losses, &c. Representative samples for use in physical and chemical tests are extracted from separators, traps, lines, or tanks as required. The loss of volatile constituents due to storing in tanks is determined by the examination of a sample consisting of specimens taken from the top, middle, and bottom of the tank.

Gathering Lines

The general scheme of pipelines in a gathering system is such that crude can be conducted from the wells by means of feeder lines to the area collecting lines, which terminate at the area flow-tank station, thence by main collecting lines to the disposal tanks.

All lines should be properly located, care spent in this direction being repaid in added operating efficiency at a later date. The course of normal development usually prevents steady and progressive location, but once production is on an assured basis overhaul and rationalization should eliminate unnecessary lines, plant, and equipment.

Attention has already been drawn to the advisability of taking opportunities presented by local topography to attain gravity flow. When this can be done and there is a possibility of gas locks occurring in the line, a survey should be run with the object of obtaining a section showing the line elevation in relation to the hydraulic gradient. Information from the section will determine the amount of grading required. Venting points should be inserted at places where gas locks might occur. These points also serve to prevent siphoning when repairs necessitate breaking into the line at a place where that phenomenon can occur.

Expansion joints for length variations due to temperature changes are seldom used, any movement of the line being taken up either at bends or in long straight stretches, by laying with an occasional serration or in long, slightly sinuous curves. Long lines connected to fixed plant such as pumps, tanks, or manifolds should incorporate means to prevent movement near the plant which might cause damage, e.g. crack the pump housing. Pipe anchors a few feet away from the rigid connexions serve the double purpose of damping any vibration which may be present and controlling movements due to expansion or contraction.

Provision of flanges or valves at suitable points facilitates breaking or repairing the line should occasion arise.

With the exception of those on large fields operated by a single company, the majority of gathering systems utilize pipe of 2, 3, 4, and 6 in. diameter. In general, line of these small sizes is screwed, although where a long production period is anticipated 4 and 6-in. line is sometimes welded. Non-standard or built-up fittings of any size are now manufactured, or made on the field, with the aid of welding. A relatively small but increasing amount of patent coupling pipeline is being laid.

The diameter required for any given service should be properly determined, given a knowledge of the properties of the crude and the flow duty for which the line is laid, by the use of one of the well-known formulae [2, 1928]. A size should be chosen which enables turbulent flow to be maintained, this being of particular importance if the crude contains paraffin wax which crystallizes at line temperatures. Lines of appreciable length carrying oil-water mixtures should be provided with traps at low points in order that water settling during transit can be drained.

Internal cleaning is performed by 'scrapers' or 'go-devils', the necessity and frequency of cleaning depending usually upon the wax content of the crude and the temperature at which it precipitates. The use of go-devils is attended with the construction of traps or by-passes at selected points for their insertion into, or extraction from, the line [12, 1935; 25, 1935]. Before clearing a line in this manner the downstream end is disconnected from traps, pumps, tanks, &c., in order that these do not act as receptacles for the dislodged detritus. This, together with oil 'chased' by the go-devil, is run into sumps prepared for the purpose in which it settles, recoverable oil being returned to the gathering system with the aid of a suitable pump. The passage of a scraper can be heard and is followed by an observer so that should it stop the position may be known. If it is being pumped along the line, strict

control is maintained on the pump-discharge pressure-gauge in order that pumping can be regulated in the event of pressure increases in the line due to blocking.

Whether on the surface or buried, every practicable precaution must be taken against corrosion, internal or external, of pipelines [14, 1935; 15; 24, 1935]. No matter how small a line may be, attention to this point is imperative.

Although internal corrosion is not so general the prevention is of supreme importance because its presence is not observed until a line is either opened for inspection or fails [18, 1935]. If pitting has reached an advanced stage the damage cannot be repaired by building up by welding as is done if the pits are on the exterior. For many reasons water is always drained away from oil-transit systems with the utmost expediency, but its presence in minute quantities can initiate acute progressive corrosion. This characteristic is intensified if the crude is sour and can only be countered by the use of special resistant steels and heavy galvanizing or similar protective treatment with a material insoluble in the fluid in transit and which neither flakes nor cracks under the exigencies of working conditions.

Corrosion by various types of soil has to be combated in different ways, and a knowledge of the properties of soil on ground to be traversed by a line is of assistance in directing the choice of suitable anti-corrosion measures and materials [5, 1935; 7, 1935]. Briefly, these consist in applying to the pipe, after it has been thoroughly cleaned, a priming coat upon which is superimposed paints of compositions to meet the prevalent conditions. The finishing coat is usually of graphite or graphite-carbon base [6, 1936]. Where heavier damage may be expected the line is coated with hot coal tar or asphalt, then wrapped treated paper, cloth, or felt in a spiral fashion, this operation being employed on small diameter lines only in extreme cases. The efficiency of these applications when paint, tar, or asphalt only is used is largely nullified unless the coat is quite impervious and the position of any uncovered spots left during the painting process is ascertained through careful checking. This can now be performed by electrically operated 'holiday locators'. Where the line rests on supports over, say, swampy ground, these must be protected, especially under and just above the surface level [17, 1935].

Safety

In the operation of a gathering system, safety is of pronounced importance and all relevant precautions have to be strictly applied.

The essence of safety is absence of free oil or gas. All leaks must be repaired, free oil attendant upon the breaking of connexions must be retained and brought back into the system or burnt under control, all plant, pressure vessels, &c., should be inspected and tested periodically to determine its degree of safety, waste gas vented to safe distance and burnt, &c. Fittings and pressure vessels must be of a type to suit the stresses to which they are subjected.

Inlet and outlet lines to any unit of plant such as separators, tanks, pumps, &c., should be blanked off when disconnected. Before being entered, empty crude or gas containers must be freed from all dangerous gas either by filling with water, steam, or inert gas. After removal of the cleansing substance, the atmosphere in the vessel should be chemically tested to determine its purity. Special care must be exercised to assure that air does not contact with dry pyrophoric iron which may be present as a corrosion scale when sour crude or gas is being handled.

Modern fire-fighting equipment is almost exclusively of the foam type, either in the form of containers or continuous generators [13, 1935]. Plant installations and tanks can be fitted with deluge sets which are fed either by pumps or gravity.

Ordinary mechanical precautions such as hand-rails, machine-guards, efficient lighting, lightning-conductors, &c., are taken as a matter of course.

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PRESSURE STORAGE OF PETROLEUM PRODUCTS

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EVAPORATION losses of volatile petroleum products during storage and transportation may assume enormous proportions, and steps must be taken to keep these losses within reasonable limits to reduce monetary loss due to the escape of a definite volume of the product, and to retain the quality of the product by preventing the evaporation of the valuable light fractions.

A considerable amount of analytical and experimental investigation has been carried out to determine the most satisfactory methods for controlling this evaporation, and a number of tanks have been developed which endeavour to prevent any escape of vapour or liquid during the time the product is stored.

Containers built to prevent escape of vapour or liquid may be classified into three groups:

A. Liquid Volume Change Tanks.
B. Vapour Volume Change Tanks.
C. Pressure Change Tanks.

It is possible that the features of all these groups may be combined in individual containers, and at the same time various temperature-control devices may be utilized.

Containers falling into group A possess the ability to adjust themselves to varying liquid volumes, always maintaining their retaining surfaces in contact with the liquid. All heat entering the tank is thus transmitted to the liquid and is expended in heating it. Tanks equipped with floating roofs fall into this group and, although not generally so considered, are really pressure devices. The liquid surface under the roof is subjected to atmospheric pressure, and before vapour can form, this pressure must be exceeded by the vapour pressure.

Vapour volume change tanks of group B possess the ability to adjust themselves to varying vapour volumes, either at constant or variable pressure. Tanks equipped with breather roofs are in this group. Any heat applied to these tanks is expended in raising the roof against atmospheric pressure. Tanks of this group are thus pressure containers, although not generally considered as such.

Containers classified as pressure change tanks possess the ability to maintain the combined liquid and vapour volume constant by withstanding internal pressures that may be developed under storage conditions. Conventional storage tanks with cylindrical shells, flat bottoms, coned or domed roofs, and conservation vents (Fig. 1) fall into this group, but are so weak structurally that they are effective over a very small pressure range. This is usually not more than 1 oz. per sq. in. Containers showing a much larger pressure range are:

(*a*) The Radial Cone Storage Tank.
(*b*) The Hortonspheroid.
(*c*) The Hortonsphere.
(*d*) The Blimp or Bullet Tank.
(*e*) The Torus or Toroid.

Each of these containers will be dealt with in detail.

The valve equipment for all pressure tanks, no matter which type, consists of one outlet valve known as the pressure-relief valve and one inlet valve known as the vacuum-relief valve. The outlet valve is set at the maximum internal gauge pressure, whilst the inlet valve is set to open at practically atmospheric pressure, usually just slightly less.

Two types of losses are possible: filling and storage losses.

Where the liquid to be stored is so volatile that its vapour pressure never falls below that at which the vacuum-relief valve opens and never exceeds that at which the pressure-relief valve opens, there can be no filling or storage losses after the first filling. This will be explained more fully when the Hortonspheroid is examined. With a variation in the liquid level, evaporation and condensation keep the pressure practically constant if the rate at which the container is emptied and filled is sufficiently slow to enable a nearly static liquid-surface temperature to be maintained by the flow of heat through the tank shell to compensate for the cooling effects of evaporation and the heating effects of condensation.

No air will be admitted to the tank if the vapour pressure remains equal to or greater than the pressure at which the vacuum-relief valve opens, but should the vapour pressure become less than this, air will enter and on subsequent filling will be ejected, carrying vapour with it.

The fraction of the entire tank capacity which can be filled immediately after emptying without loss, assuming constant temperature and saturation of the vapour space, can be stated as follows:

$$\frac{A+\phi-\nu}{A+\phi-\rho},$$

in which

A = atmospheric pressure absolute,
ϕ = gauge pressure at which the pressure-relief valve opens,
ν = the absolute pressure at which the vacuum valve opens,
ρ = the vapour pressure absolute.

The derivation of this expression is obtained simply from Boyle's law, $P_1V_1 = P_2V_2 =$ constant.

$$P_1 = (\nu-\rho)$$
$$P_2 = (\phi+A)-\nu.$$

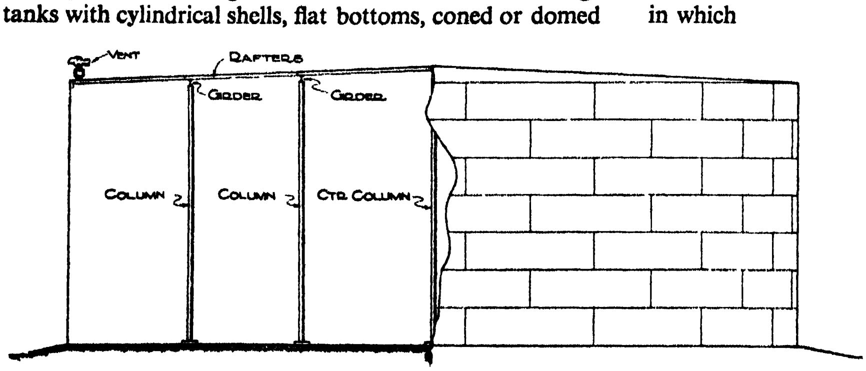


FIG. 1.

Therefore $(\nu-\rho)V_1 = (\phi+A-\nu)V_2$,

or $$\frac{V_2}{V_1} = \frac{\nu-\rho}{\phi+A-\nu}.$$

Then $$1-\frac{V_2}{V_1} = 1-\frac{\nu-\rho}{\phi+A-\nu},$$

or $$\frac{V_1-V_2}{V_1} = \frac{\phi+A-\rho}{\phi+A-\nu}.$$

But the final volume $= \dfrac{V_1}{V_1-V_2}$.

Therefore final volume $= \dfrac{\phi+A-\nu}{\phi+A-\rho}$.

In the discussion on any evaporation problems it is desirable to have an expression giving the approximate number of cubic feet of saturated gasoline vapour per gallon of liquid gasoline. An expression which will give a very near approximation can be derived as follows:

From Avogadro's hypothesis it is known that the pound molecular weight of any substance existing as a gas will occupy 359 cu. ft. at 32° F. and atmospheric pressure. At 32° F. and atmospheric pressure a particular substance may not exist as a gas, but nevertheless Avogadro's hypothesis, together with Boyle's and Charles' law, may be applied to calculate the pound molecular volumes at temperatures and pressures for which the substance does exist as a gas or as a saturated vapour.

Let W = weight of 1 gal. of liquid, lb.,
M = molecular weight, lb.,
T = saturated vapour temperature, ° F.,
ρ = saturated vapour pressure at temperature T,
A = Atmospheric pressure = 14·7 lb. per sq. in.,
Z = number of cubic feet of saturated vapour per gallon of liquid.

Then $359\dfrac{W}{M}$ = number of cubic feet of gas at 32° F. and 14·7 lb. per sq. in. pressure containing 1 gal. of liquid.

$359\dfrac{W}{M}\dfrac{(T+460)}{(32+460)} = 0{\cdot}73(T+460)\dfrac{W}{M}$ = number of cubic feet of gas at temperature T and 14·7 lb. per sq. in. pressure containing 1 gal. of liquid if the substance existed as a gas at this temperature and pressure.

Finally, since densities vary directly and therefore volumes vary inversely as the pressure,

$Z = 0{\cdot}73(T+460)\left(\dfrac{W}{M}\right)\left(\dfrac{A}{\rho}\right)$ = number of cubic feet of saturated vapour per gallon of liquid.

Pentane and hexane are largely responsible for the vapour pressures and liquid contents of the vapours of the lighter petroleum products. For pentane $W = 5{\cdot}3$ and $M = 72$ lb.; for hexane $W = 5{\cdot}6$ lb. and $M = 86$ lb. Let T be taken as 80° F. Then for pentane

$$Z = 0{\cdot}73(80+460)\frac{5{\cdot}3}{72}\frac{(A)}{(\rho)} = 29\frac{(A)}{(\rho)}.$$

For hexane,

$$Z = 0{\cdot}73(80+460)\frac{5{\cdot}6}{86}\frac{(A)}{(\rho)} = 25{\cdot}7\frac{(A)}{(\rho)}.$$

The expression $Z = 30(A)/(\rho)$ is much used, and the results obtained for pentane and hexane would appear to warrant the use of such a value. The fact that pentane at atmospheric pressure boils at approximately the same temperature as commercial gasoline permits the value $30(A)/(\rho)$ to be used for this product.

Using the expression $30(A)/(\rho)$ in conjunction with Boyle's and Charles' law, and the assumptions of a saturated vapour space and a vacuum valve opening at atmospheric pressure, it can readily be shown that the filling loss, F, in barrels of liquid per 1,000 bbl. of tank capacity is given by the expression

$$F = 4{\cdot}45\left(\frac{\rho}{A}\right)\left(\frac{A-\rho}{A+\phi-\rho}\right).$$

Using Boyle's Law, $P_1V_1 = P_2V_2$ = constant.

$$(A-\rho)V_1 = (A+\phi-\rho)V_2\times 30\frac{(A)}{(\rho)}.$$

V_1 = 1,000 bbl. = 5,600 cu. ft. and $30(A)/(\rho)$ = cu. ft. per gal.

Therefore $V_1 = 30\times 42(A)/(\rho)$ cu. ft. per bbl., since there are 42 gal. to the bbl., and therefore

$$\frac{(A-\rho)}{(A+\phi-\rho)}\times\frac{1}{30\times 42}\left(\frac{\rho}{A}\right)\times 5{,}600 = V_2 = F,$$

or $$F = 4{\cdot}45\frac{(\rho)}{(A)}\frac{(A-\rho)}{(A+\phi-\rho)}.$$

In this expression

ϕ = gauge pressure setting of the pressure-relief valve,
ρ = absolute vapour pressure,
A = atmospheric pressure, absolute.

It can also be shown that the vapour pressure ρ_m, resulting in the maximum possible filling loss for a given value of ϕ, is

$$\rho_m = (A+\phi)\left[1-\sqrt{\left\{1-\left(\frac{A}{A+\phi}\right)\right\}}\right].$$

Expanding equation for filling loss F previously obtained,

$$\frac{(A\rho-\rho^2)}{A^2+A\phi-A\rho}\times 4{\cdot}45 = F.$$

And differentiating with respect to ρ

$$\frac{dF}{d\rho} = (A^2+\phi A-\rho A)(A-2\rho)-(A\rho-\rho^2)(-A) = 0,$$

or simplifying

$$\rho^2-2\rho(A+\phi)+A(\phi+A) = 0.$$

Therefore

$$\rho_m = (A+\phi)\left[1-\sqrt{\left\{1-\left(\frac{A}{A+\phi}\right)\right\}}\right].$$

The accompanying graphs, Fig. 2, show the values of F, as ordinates, plotted against values of ρ in lb. per sq. in. as abscissae.

Curves are shown for ϕ for values of 0, 5, 10, and 15 lb. per sq. in. The difference between the values of F for any value of ϕ and the corresponding values of F for $\phi = 0$ represent the savings due to filling against the gauge pressure ϕ as compared with fillings at atmospheric pressure.

Filling losses from products with vapour pressures less than zero gauge pressure may be prevented or reduced either by partly filling the tank and thus utilizing the upper portion merely to hold air under pressure, or by designing and operating the tank to withstand a partial vacuum equal to the difference between atmospheric pressure and the minimum vapour pressure. Maintaining the tank at a normal temperature during cold periods would also be effective, and this could be accomplished by external heating.

During the period when the contents of the tank remain undisturbed the tank will be affected by variations in temperature. During the night the tank will usually lose heat to the atmosphere; during the day it will usually receive heat from the sun. Heat will also be exchanged between the earth and the tank. Radiation, convection, and conduction all take part in these temperature changes whether the heat is incoming or outgoing.

During the cooling periods convection currents are most effective. The upper and side layers of liquid and vapour, which are the first portions to lose heat, fall to lower levels by reason of their greater density, and warmer and lighter portions rise to take their place. During the warmer periods, on the other hand, the upper layers receive heat first and by conduction pass some of it to the cooler layers below.

As a result of this the vapour space is practically, if not wholly, saturated at the end of a prolonged cooling period, with nearly uniform conditions of temperature, pressure, and density. During the periods when the tank is heating up there is a falling temperature gradient and a rising density gradient from the roof to the liquid, and a vapour-space pressure which may be considered uniform.

Some of the heat which falls on a tank is reflected, some is absorbed by the steel, and the remainder passes into the tank where it is expended in heating the vapour and air, if air is present, in heating the gasoline, in evaporating a portion of the gasoline and, for volume change tanks, in enlarging the vapour space against atmospheric or higher pressure.

The conditions in a tank are all affected by a number of factors, among which are the radiating and reflecting properties of the material from which the tank is fabricated, the specific heats and thermal conductivities of the material, air, vapour, and gasoline, the heat of vaporization of gasoline, the retarding effect of air on the diffusion of vapour, the effects of convection currents, and the vagaries of the climatic conditions.

To determine the proper storage pressure for a particular product in a specified area would necessitate highly involved calculations of questionable accuracy, and designers rely upon weather records for the area, upon service records of similar tanks storing similar products in the same or similar climatic conditions, and upon experimental data and good judgement.

It may reasonably be assumed, in the absence of specific information, that, for any particular season of the year, the liquid-surface and vapour-space temperature at the coldest part of each day is the average atmospheric temperature for the season, that the maximum liquid-surface temperature for any particular day in a nearly full tank is 20° F. higher than the average atmospheric temperature for the season, and that the average temperature range in the vapour space is $1\frac{1}{4}$ times the daily atmospheric temperature range. The vapour pressures corresponding to the liquid-surface temperatures may be obtained from a vapour pressure versus temperature chart similar to that shown in Fig. 3.

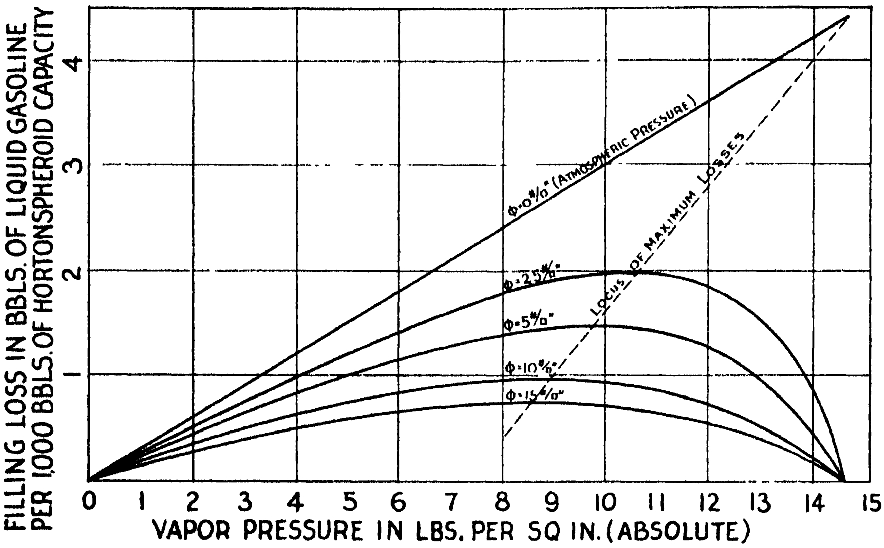


Fig. 2.

It is possible to derive an expression for the daily evaporation loss in gallons of liquid gasoline per 1,000 cu. ft. of vapour space measured at the coldest time of a particular day, and from this to obtain an expression from which the required storage gauge pressure to eliminate all standing storage losses may be estimated.

Let

L = the daily evaporation loss in gallons of liquid per 1,000 cu. ft. of vapour space measured at the coldest time of a particular day,

p = the absolute vapour pressure at the coldest time of the day,

P = the absolute vapour pressure at the hottest time of the day,

t = the Fahrenheit temperature of the vapour space at the coldest time of day,

T = the average Fahrenheit temperature of the vapour space at the hottest time of day,

v = the absolute pressure at which the vacuum valve opens, usually a little below atmospheric pressure,

ϕ = the gauge pressure at which the pressure-relief valve opens,

A = atmospheric pressure—14·7 lb. per sq. in.

$$\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2}.$$

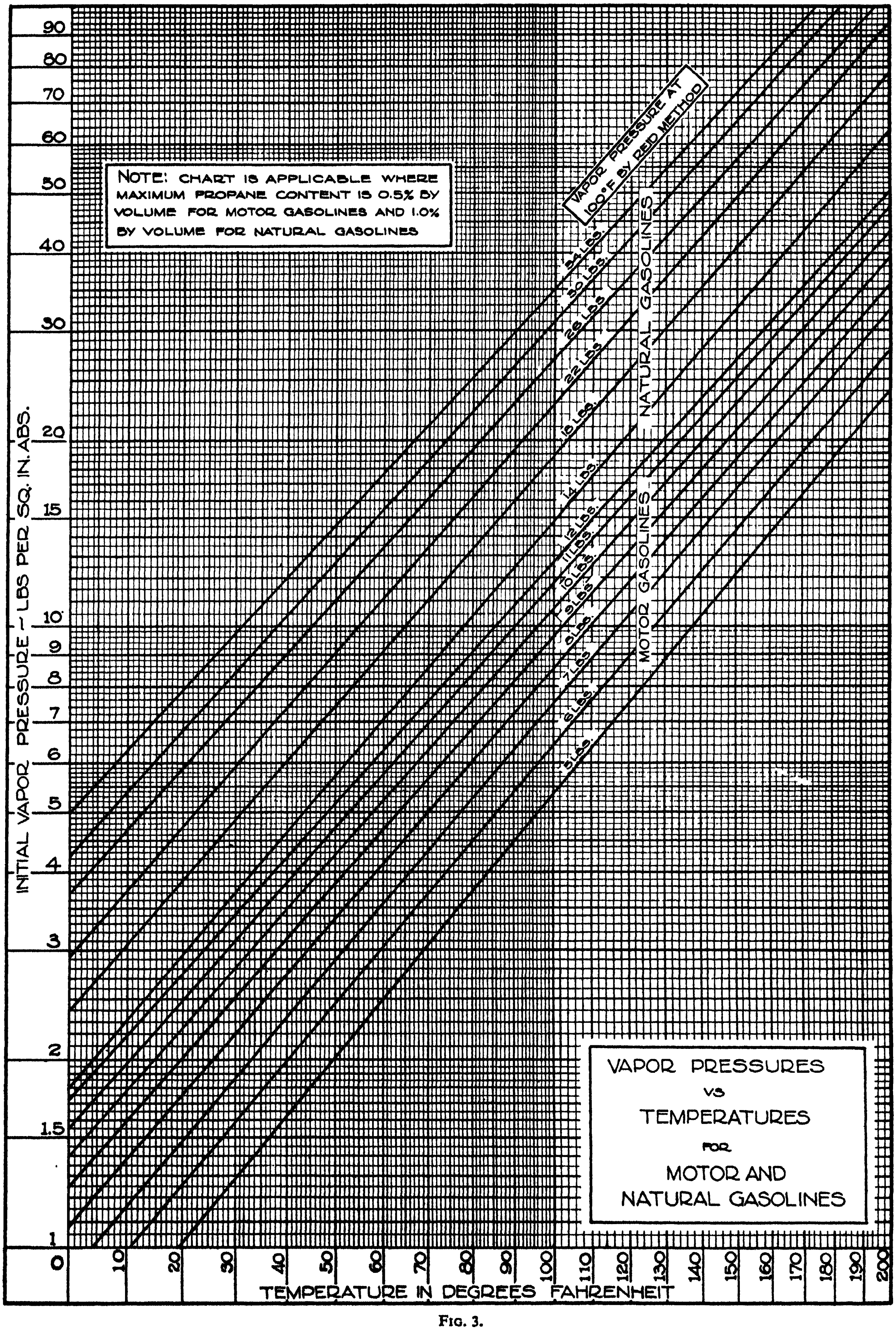

NOTE: CHART IS APPLICABLE WHERE MAXIMUM PROPANE CONTENT IS 0.5% BY VOLUME FOR MOTOR GASOLINES AND 1.0% BY VOLUME FOR NATURAL GASOLINES
VAPOR PRESSURE AT 100°F BY REID METHOD
NATURAL GASOLINES
MOTOR GASOLINES
VAPOR PRESSURES VS TEMPERATURES FOR MOTOR AND NATURAL GASOLINES
INITIAL VAPOR PRESSURE ~ LBS PER SQ. IN. ABS.
TEMPERATURE IN DEGREES FAHRENHEIT

FIG. 3.

Therefore $(\nu-\rho)(T+460)V_1 = (A+\phi-P)(t+460)V_2$,

or
$$\frac{(\nu-\rho)(T+460)}{(A+\phi-P)(t+460)} = \frac{V_2}{V_1},$$

$$\left[\frac{(\nu-\rho)(T+460)}{(A+\phi-P)(t+460)}-1\right] = \frac{V_2-V_1}{V_1}.$$

$\frac{V_2-V_1}{V_1}$ = loss per cu. ft. of original vapour.

$\frac{V_2-V_1}{V_1}\times 1{,}000$ = loss per 1,000 cu. ft. of original vapour.

$$\frac{V_2-V_1}{V_1}\times 1{,}000\times\frac{(P-\rho)}{1{,}000}$$

= loss in gal. per cu. ft. per 1,000 cu. ft. = L,

i.e.
$$\frac{V_2-V_1}{V_1} = \frac{L}{(P+\rho)}.$$

Therefore
$$\left[\frac{(\nu-\rho)(T+460)}{(A+\phi-P)(t+460)}-1\right] = \frac{L}{(P+\rho)}.$$

Or
$$L = (P+\rho)\left[\frac{(\nu-\rho)(T+460)}{(A+\phi-P)(t+460)}-1\right],$$

when $L = 0$, that is when there are no losses,

$$\phi = (\nu-\rho)\frac{(T+460)}{(t+460)}-(A-P),$$

an expression from which the required storage gauge pressure ϕ to eliminate all standing storage losses may be estimated using the most unfavourable seasonal, not daily, temperature conditions of the year.

These equations show that if $\nu = \rho$, no losses will occur, and that if $\nu = \rho$, $\phi = (P-A)$. These are the relations when no air enters the tank, and they indicate the conservation value of a vacuum valve opening at as large a partial pressure as the tank will safely withstand.

As an illustration of the remarkable reduction in evaporation losses effected by low storage pressures, let the following reasonable data be assumed.

ρ = 4·5 lb. per sq. in.	P = 6 lb. per sq. in.
t = 80° F.	T = 100° F.
ν = 14·7 lb. per sq. in.	ϕ = 1 lb. per sq. in.

Then
$$L = (4{\cdot}5+6)\left[\frac{(14{\cdot}7-4{\cdot}5)(100+460)}{(1+14{\cdot}7-6)(80+460)}-1\right] = 0{\cdot}95 \text{ gal.}$$

If $\phi = 0$, the loss would have been
$$L = (4{\cdot}5+6)\left[\frac{(14{\cdot}7-4{\cdot}5)(100+460)}{(14{\cdot}7-6)(80+460)}-1\right] = 2{\cdot}25 \text{ gal.}$$

There would, therefore, have been more than twice as much loss when the gauge pressure, at which the pressure-relief valve opens, is zero.

Substituting these same data in equation
$$\phi = (\nu-\rho)\frac{(T+460)}{(t+460)}-(A-\rho)$$

it will be seen that all standing losses will be eliminated when ϕ = 1·9 lb. per sq. in.

$$\phi = (14{\cdot}7-4{\cdot}5)\frac{(100+460)}{(80+460)}-(14{\cdot}7-6) = 1{\cdot}9 \text{ lb. per sq. in.}$$

The Wiggins Breather Roof.

The Wiggins Breather Roof is a gas-tight structure which permits a variable volume for the air-vapour mixture accumulating above the oil. The construction is shown in Fig. 4.

The roof is composed of plates, welded together to form a huge diaphragm, and is fastened securely to the angle at the top of the tank shell. The roof, when in its normal position, rests on a steel framework erected within the tank. It is in no way attached to this framework. Movement from the lowest position on the framework to an upward bulging position is thus possible.

The outer rafters of the framework slope downwards and inwards from the top of the shell forming an inverted frustum of a cone, the tops of the inner rafters lying in a horizontal plane 10 in. below the top of the tank shell.

A mechanically operated volume-relief valve is placed in the roof so that, when the Breather is unable to accommodate the accumulated air and vapour, a condition that may arise during filling as well as at other times, the tank may be vented. A vacuum-relief valve admits air whenever the internal gauge pressure drops below zero.

During the coolest part of the day the roof rests upon the framework, but with an increase of temperature the air-vapour mixture expands, and instead of a portion of it being forced out of the vent the roof rises sufficiently to provide the increase in volume space required. Providing the volume-relief valve is set to operate at some temperature greater than that likely to be normally experienced, the roof rises to allow for any expansion that may take place inside the tank, and no losses are incurred. A breather roof, therefore, eliminates almost completely standing losses, but does not eliminate filling losses.

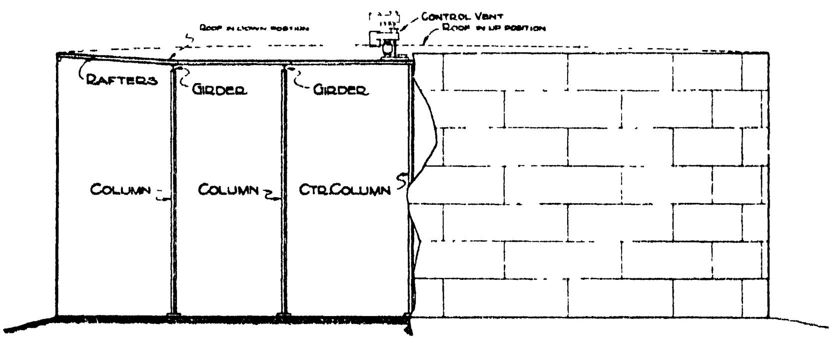


FIG. 4.

The Radial Cone Storage Tank.

The Radial Cone Storage Tank, as shown in Fig. 5, is an adaptation of the conventional cylindrical storage tank to pressure storage. The shell is a vertical cylinder, the roof and bottom each consisting of a number of radial inwardly concave troughs connected along their radial edges to radial girders. Both girders and troughs are connected to the shell. The upper girders are directly above the lower ones and are connected to them by vertical members which serve as ties when there is internal gas-pressure, and as columns when there is not. Welded construction is preferred for these tanks, although riveting is satisfactory.

Each radial cone tank is designed to withstand the maximum pressure required to prevent vapour losses, and is provided with a special relief valve to open when that pressure

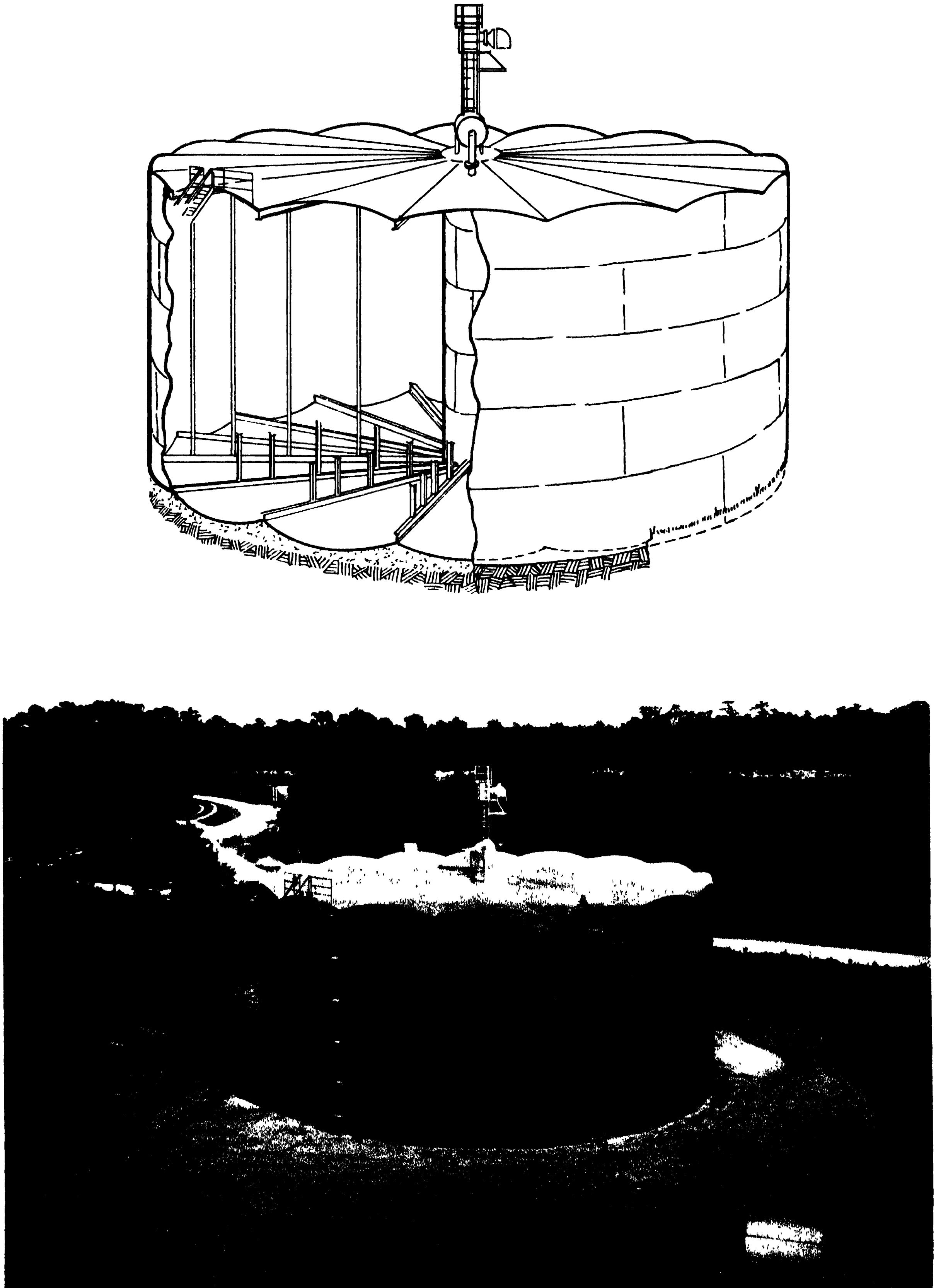


Fig. 5

Radial cone storage tank

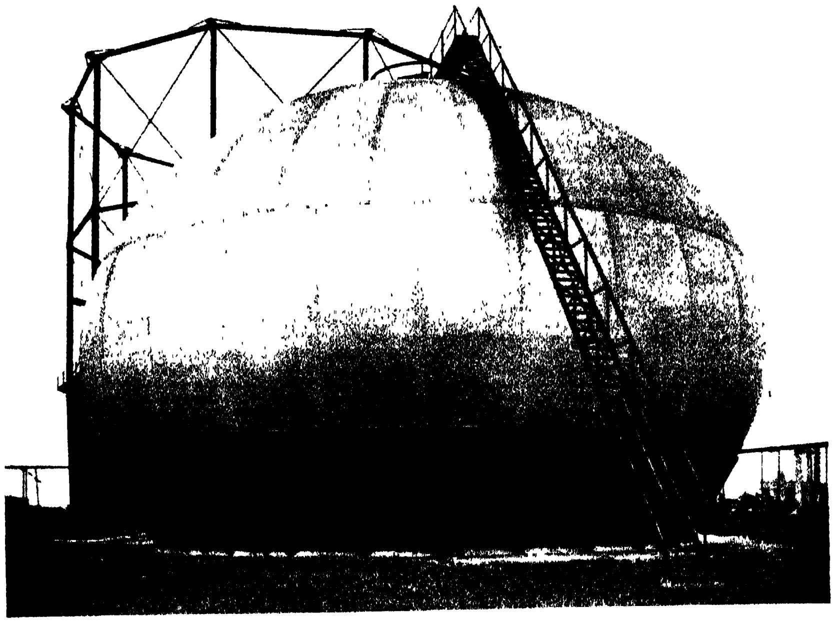
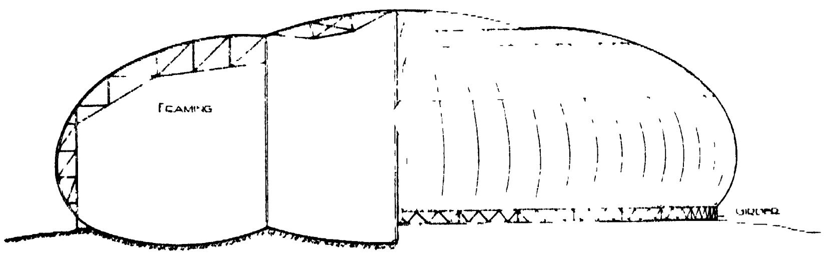


Fig. 7



Hortonspheroid

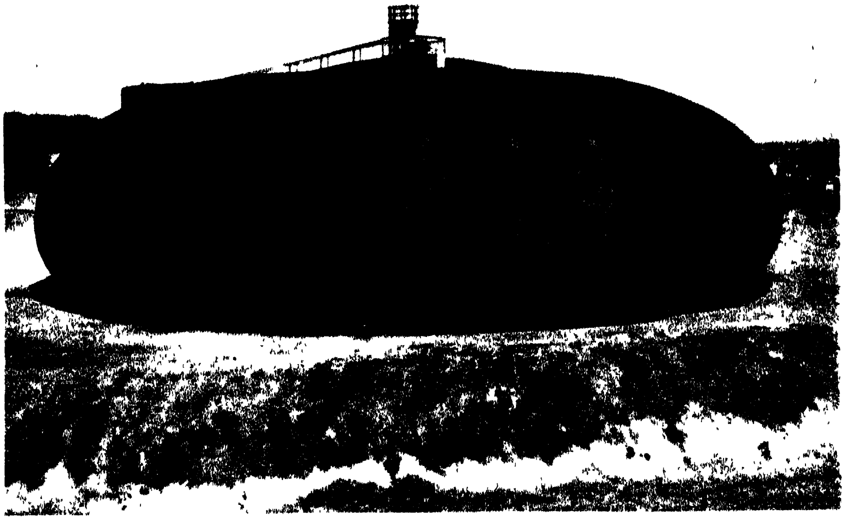


Fig. 8

is reached and a special vacuum valve to admit air if the gauge pressure drops a little below zero.

Radial cone tanks are suitable for operating gauge pressures up to 10 lb. per sq. in., and although they can be built in practically any sizes, are especially recommended for capacities ranging from 30,000 to 80,000 bbl.

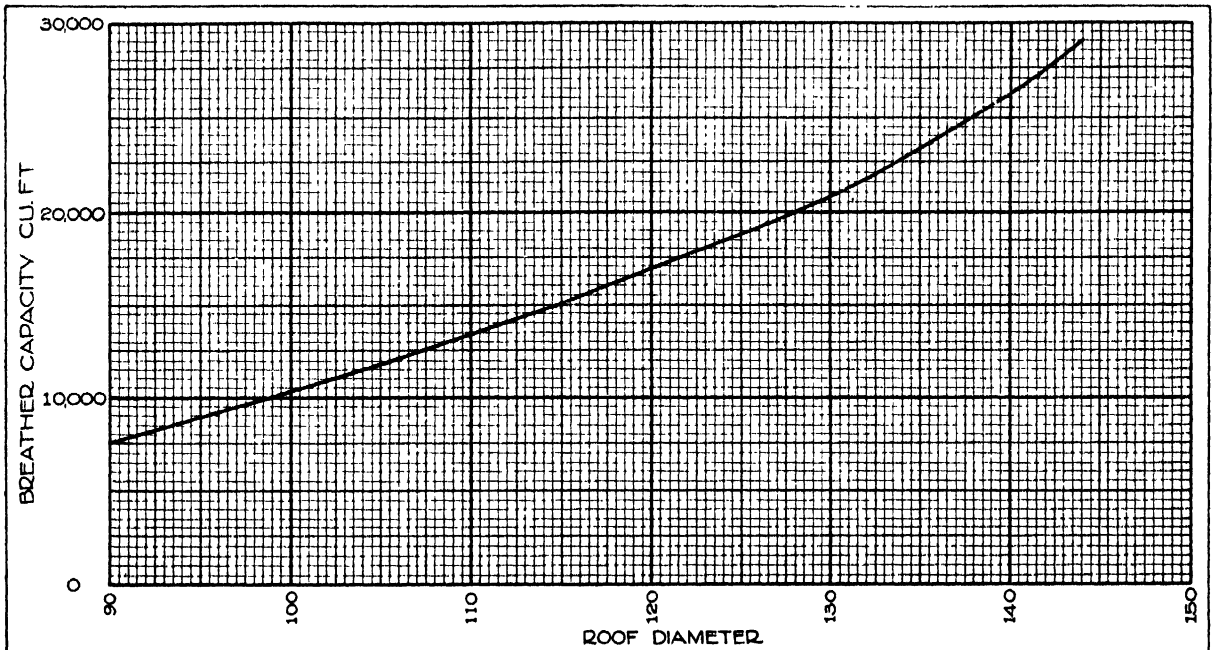
The Torus and Toroid.

The Torus, illustrated in Fig. 6, may be described as an endless cylinder in the form of a ring. If the cylinder is rectangular instead of circular in cross-section, the structure is called a Toroid.

None of these structures is in actual service.

The Hortonspheroid and Hortonsphere.

Hortonspheroids are of two types; the first shown in Fig. 7 usually having no internal bracing, but the general form of a drop of mercury on a nearly flat surface; the second shown in Fig. 8 having internal radial trusses and the general shape of one or more concentric intersecting



BREATHER ROOF CAPACITIES

Toruses or Toroids and a central sphere. The overlapping portions are omitted, and circular girders on the corresponding upper and lower node circles are connected by members capable of acting either as columns or ties. Each type of Hortonspheroid is equipped with an outside girder for supporting the weight of liquid on the overhanging portion and for otherwise strengthening the structure.

All internal pressures are resisted by stresses in all directions in planes tangential to the shell.

The Hortonspheroid may be used for storing volatile liquids for any pressure up to 20 lb. per sq. in., whilst the noded spheroid is recommended for low-pressure storage in tanks of large capacity, for gauge pressures from 1 to 5 lb. per sq. in.

The principle of the Hortonspheroid is as follows. When a volatile liquid is stored in a sealed tank it exerts a pressure in proportion to its vapour pressure at the temperature existing. Any air

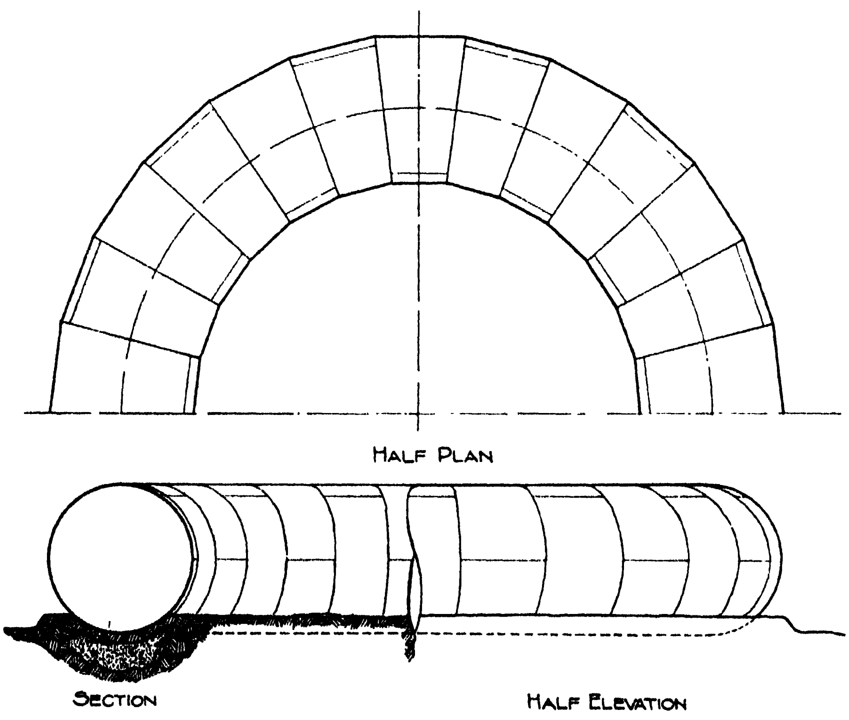


FIG. 6. The Torus.

which is present increases this pressure, the partial pressures of the vapour and the air being in the proportions of their mol. fractions, and the total pressure is the sum of the partial pressures of the vapour and air present.

This tank is designed to withstand a certain maximum pressure, and the relief valve with which it is fitted may be adjusted to operate at any desired working pressure determined by the vapour pressure of the liquid to be stored.

Assume that the pressure-relief valve is set to operate at a pressure of 2 atm. and the vacuum valve is adjusted to open at a pressure just slightly below 1 atm. As the liquid enters the tank, vapour mixes with the air. When the total pressure of the two components exceeds 2 atm. the pressure-relief valve opens, causing an escape of the vapour-air mixture. When the tank is emptied, assuming no change of temperature and vapour pressure, no air can be admitted by the vacuum valve, provided the vapour pressure of the liquid does not fall below 1 atm. and the liquid evaporates and fills the space above the liquid as the level falls. After the first filling, therefore, no air will be present in the tank, since it was then expelled and the vacuum valve will be maintained closed by the vapour pressure within the spheroid, and all future fillings and emptyings will be carried out without loss. This is an ideal case.

Assume now that the spheroid is filled with a gasoline having a vapour pressure below 1 atm., say, 10 lb. per sq. in. abs., the pressure-relief valve is set at 25 lb. per sq. in. abs. and the vacuum-relief valve is to operate at slightly below 1 atm. pressure.

At the commencement the tank is filled with air at a pressure of approximately 15 lb. per sq. in. abs. As gasoline is admitted the air becomes saturated with petrol vapour and the pressure gradually rises until it reaches 25 lb. per sq. in. abs. when the relief valve will open, and as the level continues to rise vapour will be expelled. On emptying, assuming no change in temperature or vapour pressure, more vapour is formed to fill the space above the falling liquid-level, but since the vapour pressure is only 10 lb. per sq. in. abs. air is drawn in through the vacuum-relief valve until the total pressure reaches that of the atmosphere.

Refilling the container with the same gasoline, assuming the partial pressure of the air in the vapour-air mixture to be 5 lb. per sq. in. at the commencement, results in the pressure of the air increasing to 15 lb. per sq. in. before the pressure-relief valve opens. The tank could, therefore, be filled approximately two-thirds full without loss of vapour. This can be shown by substitution in the equation previously determined.

$$\frac{A+\phi-v}{A+\phi-p}=\frac{15+10-15}{15+10-10}=\frac{10}{15}=\frac{2}{3}.$$

The Hortonsphere, shown in Fig. 9, is a pressure container in the form of a sphere which may be equipped with an external girder and supported directly on the ground or carried on several columns resting on concrete piers. It may be riveted or welded.

These tanks are used primarily for the storage of products requiring a storage gauge pressure higher than 20 lb. per sq. in. The principles are the same as for the Hortonspheroid.

The Blimp.

The Blimp or Bullet tank, shown in Fig. 10, is a pressure container consisting of a cylindrical shell and hemispherical ends. In this type the pressure exerted on the inside of the shell is resisted entirely by ring tension, and in order to withstand the higher pressures more metal is required.

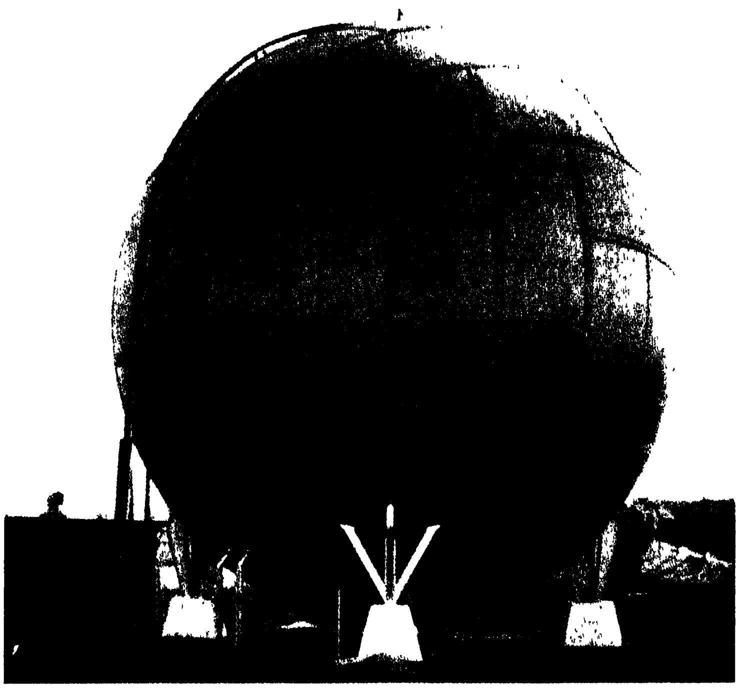


FIG. 9 The Hortonsphere

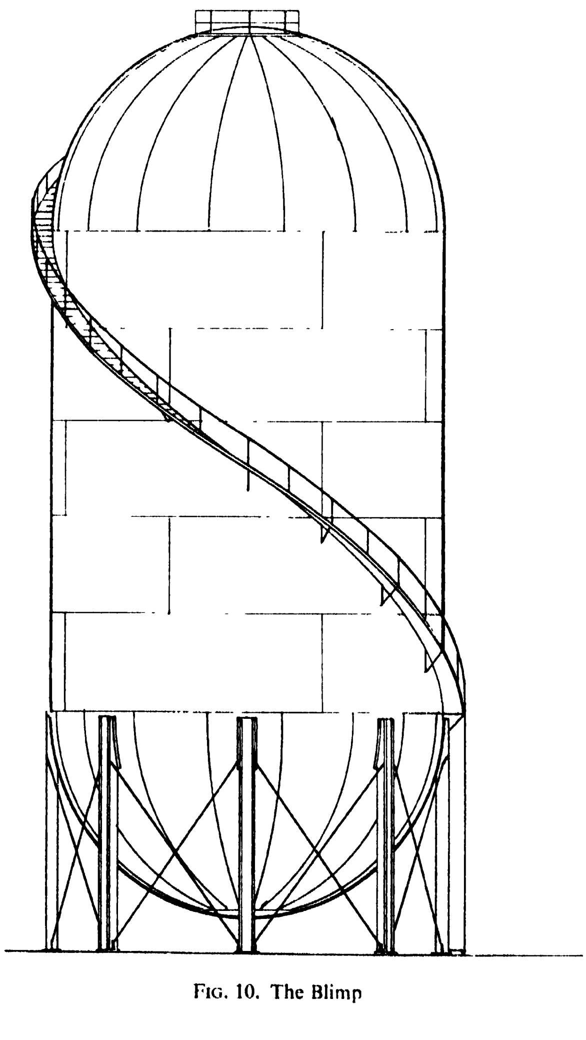


FIG. 10. The Blimp

FLOATING ROOFS

By DONALD E. LARSON

Research Department, Chicago Bridge and Iron Works

A FLOATING roof on an oil-storage tank has two principal functions: to minimize evaporation loss, and to reduce fire hazard.

When volatile liquid is stored in a tank having a fixed roof some of it is lost by evaporation. This loss is made up of one or more of the following parts:

(1) The loss caused by the breathing which accompanies temperature changes.
(2) The loss resulting from the displacement of vapour by liquid when the tank is filled.
(3) The loss occurring when any part of the liquid reaches the boiling temperature.

A roof floating directly on the oil eliminates the vapour space and prevents both breathing and filling losses. In addition boiling losses from the more volatile products may be reduced by providing a shading system to lower the temperature of the surface liquid, or by so constructing the roof that vapour formed by boiling is trapped and retained until recondensed by cooler night temperatures.

A floating roof prevents fire by eliminating the conditions which might permit the contents of a tank to burn. Oil under the deck cannot ignite because air is excluded, and an explosive mixture cannot form above the deck because it is not confined. Fire can occur only in the space between the rim of the roof and the tank shell. This space, however, is sealed with a fire-resistant material, and tests have proved that a fire started there dies out quickly.

Types of Floating Roofs

Nearly all floating roofs in actual service fall within the following classifications:

(1) **The Pan-type Floating Roof.** The Pan-type roof consists of an essentially flat metal deck with a vertical rim at the periphery. The deck is coned slightly downward towards the centre and held in shape by radial trusses. A cross-section of a tank containing a Wiggins Pan-type Roof is shown in Fig. 1. This roof will safely sustain a load equivalent to 6 in. of water over the entire deck, but has the disadvantage that a leak will cause it to sink. Pan-type roofs are effective in preventing evaporation losses from products not sufficiently volatile to boil at the highest temperature attained by the steel deck. However, the recent trend towards the use of more volatile motor fuels has created a demand for more adequate protection than these roofs afford.

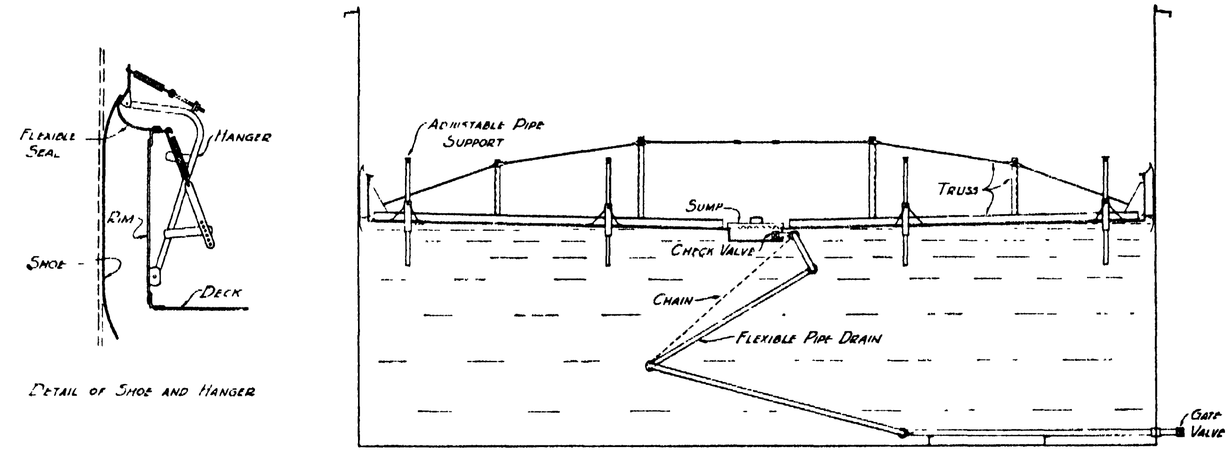


FIG. 1. Wiggins Pan-type Floating Roof.

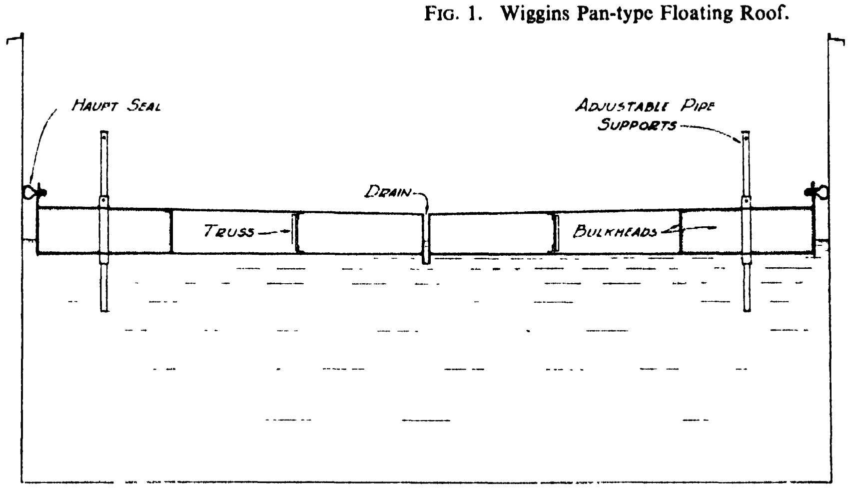


FIG. 2. Double-deck Pontoon Roof with Haupt Seal.

(2) **The Double-deck Pontoon Roof.** The roof shown in Fig. 2 consists of a pontoon divided by bulkheads into compartments which make it practically non-sinkable. Should a leak develop in any one compartment, the roof will be kept afloat by the others. Breathing and filling losses are prevented by elimination of the vapour space, and boiling losses are reduced by the shading which the upper deck provides. Roofs of this type are frequently used for tanks having diameters of about 35 ft. or less, but are

seldom used for larger tanks because the cost of two complete decks is prohibitive.

(3) **The Wiggins Pontoon Roof.** The Wiggins Pontoon Roof, illustrated in Fig. 3, has an unstiffened centre deck attached to an annular pontoon divided into compartments by radial bulkheads. The proportions of the roof are such that it will not tip or sink even though the centre deck is filled with water to the top of the pontoon. Leaks in the deck or in several of the pontoon compartments will not submerge the roof because the remaining compartments have adequate buoyancy to keep it floating. The entire roof normally rests directly on the oil, thus preventing breathing and filling losses, but when vapour is formed by boiling, the centre deck flexes upward, trapping the vapour and retaining it until recondensed by lower temperatures. In hot weather, several inches of water may be carried on the centre deck to prevent boiling if the tank contains an unusually volatile product. Since the buoyancy of this roof is ample to ensure freedom from operating difficulties, and since the cost is commensurate with the evaporation savings effected, it is more widely used than any other type of floating roof.

The Seal

Tanks sometimes become distorted due to foundation settlement, and the diameter of the floating roof must be made about 16 in. less than the tank diameter to prevent the roof from sticking. The space between the roof rim and the tank shell must be provided with a flexible seal, and the effectiveness of the roof in preventing evaporation loss depends largely on the tightness of this seal. Seals may be divided into two general classes:

(1) **The Deep Narrow Slot Seal.** This seal may be defined as one in which the sealing element extends continuously from below the liquid surface to a point 20 in. or more above it. The Wiggins Seal, which is of this type, employs a series of steel shoes curved at top and bottom to permit easy passage over rivet-heads and plate laps. These shoes are supported and held against the tank shell by spring hangers attached to the roof. Adjacent shoes are connected by vertical strips of flexible material called the intershoe seals, and the tops of all shoes are connected to the roof by a continuous strip of flexible seal called the continuous seal. This type of seal is effective in preventing losses even when all of the shoes are held away from the tank shell by the rivet-heads at a horizontal seam. Only a small portion of the total surface area is exposed and the vapour which forms in the narrow slot between the shoes and the shell tends to form a blanket preventing further evaporation. The flexible seal material consists of an asbestos cloth base having an inert compound such as Thiokol vulcanized into it on both sides. This provides a fire-resistant, gas-tight seal which does not deteriorate under severe weather conditions. The Wiggins Seal is illustrated in Figs. 1 and 3.

(2) **The Line Contact Seal.** This seal is one in which the sealing element contacts the shell along a horizontal line above the liquid surface. To be effective, the seal must make a continuous and positive contact with the tank shell. Because a few small openings will permit evaporation losses due to circulation of air in the rim space, seals of this type have not been widely used on roofs for riveted storage tanks. They are, however, suitable for welded tanks having smooth interior surfaces. The double-deck pontoon roof shown in Fig. 2 is equipped with a Haupt seal in which contact with the shell is maintained by a loop of flexible material.

Roof Supports

A set of roof supports must be provided for every floating roof, because tank connexions make it impractical to allow the roof to rest directly on the bottom when the tank is empty. The following types are suitable:

(1) **Pipe Supports.** Adjustable supports consisting of outer pipe sleeves welded to the roof and inner pipes which bear on the tank-bottom may be used with any type of roof. The two pipes are connected by a pin, and it is standard practice to provide two sets of holes, as shown in Fig. 1, so that the roof may be supported 3 ft. above the tank-bottom for ordinary operation, or 6 ft. above the bottom for cleaning. This type of support is advantageous because the roof may be supported at either of two different levels by using only one set of supports.

(2) **Fixed Structural Supports.** Wiggins Pontoon Roofs are usually supported in the low position on a structural framework which will safely sustain the roof and all the water that can accumulate on the deck. This framework, which is illustrated in Fig. 3, aids materially in the erection of the roof. Its disadvantage is that some additional means must be provided for supporting the roof in a higher position.

(3) **Link Hangers.** Hangers consisting of three pin-connected links may be used for suspending the roof in the 6-ft. position. As the roof descends, one end of each hanger is attached to the roof and the other is fitted into a slot formed by small angles welded to the tank shell. The links then gradually become taut and support the roof. These hangers can be used only for roofs having sufficient strength to be supported at the edges alone. One set of link hangers can be used for several roofs as it is seldom necessary to clean more than one tank at a time.

Drainage Systems

Most tanks equipped with floating roofs do not have weather roofs over the top; therefore it is necessary to provide a drain to remove rain-water from the deck. Several types have proved satisfactory.

(1) **Pipe Drains with Flexible Joints.** A pipe drain of the type shown in Fig. 1 may be used with any floating roof. A check-valve is provided at the inlet, and a gate-valve is installed at the outlet. In the event of an accident causing the drain to leak, the check-valve in the sump may be closed to prevent oil from flowing on to the deck. The gate-valve at the outlet is normally kept closed, but should be opened after every rain of any consequence and during especially heavy rains. A drain of this type is advantageous because it removes water from the roof without permitting it to come into contact with the oil in the tank.

(2) **Short Pipe Drains.** A double-deck pontoon roof of the type shown in Fig. 2 may be equipped with a drain consisting of a short pipe extending through both decks. Rain-water falling on the deck flows into the pipe and down through the oil to the tank-bottom where it can be removed through the water draw-off. These drains are free from operating difficulties, but cannot be used in cases where it is undesirable to have water making contact with the tank contents. Short pipe drains can be used only in connexion with roofs in which the upper deck is everywhere above the liquid surface.

(3) **Inverted Syphon Drains.** The operation of the syphon drains used with Wiggins Pontoon Roofs is based upon the fact that water is heavier than oil. The roof in Fig. 3 is equipped with one of these drains. A coupling is welded

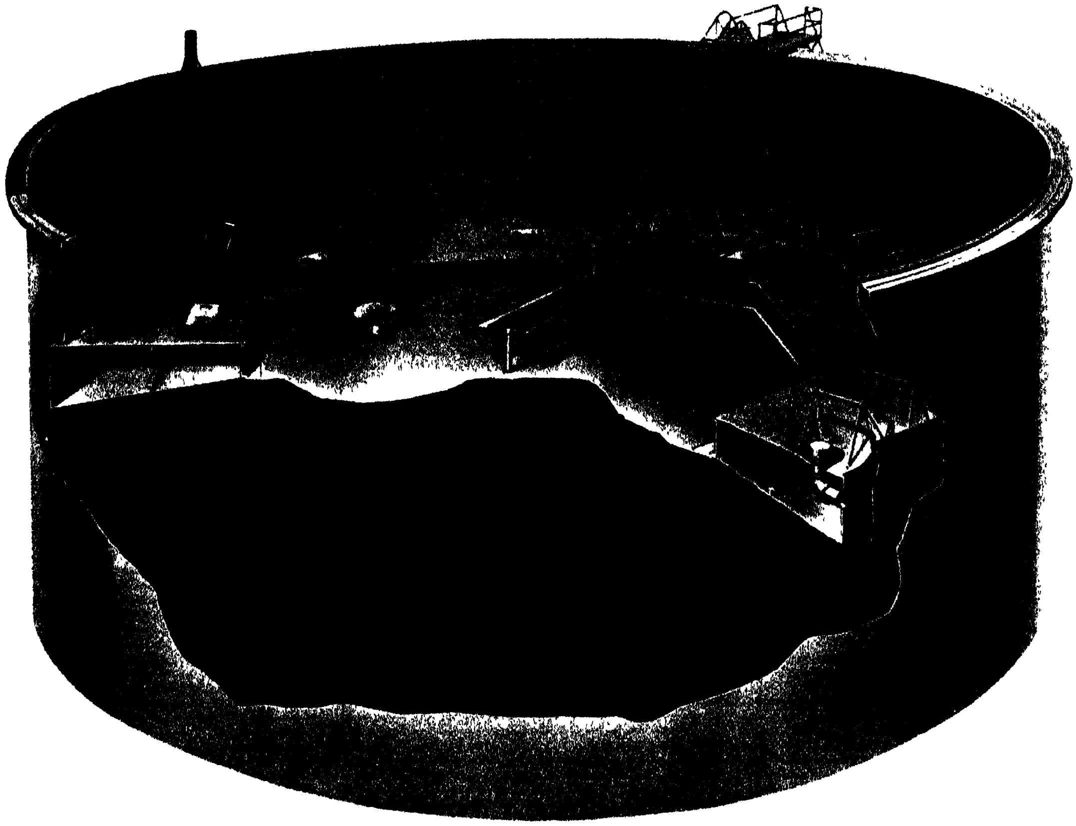


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FIG. 3. Wiggins Pontoon Roof

to the deck and a pipe with a pan attached to the lower end is screwed into the coupling from the underside of the deck. Another piece of pipe with a cap on one end is screwed into the coupling from the upper side of the deck. To put the drain into operation it must be primed by removing the cap from this plug pipe and pouring in enough water to fill the pan. Since water is heavier than oil, the liquid-level in the pipe will be below the deck and the plug pipe may be removed. Any water on the deck will then flow into the drain, causing the water in the pan to overflow and descend to the tank-bottom. Although the pan has sufficient capacity to prevent the syphon from becoming unprimed under normal conditions, the plug pipe should be left in place during long periods of dry weather to prevent the drain from reversing due to loss of water by evaporation.

Ladders and Stairways

Some means must be provided for gaining access to the roof from the top of the tank shell. The following types of ladders or stairways may be employed:

(1) **Rolling Stairway.** The stairway most frequently used is a ladder hinged at the upper end and equipped at the lower end with wheels which roll on a runway above the deck as the roof rises and falls. This type of stair, which is illustrated in Fig. 3, may be used on almost any roof, provided the height of the tank is not greater than the diameter. The ladder is equipped with hand-rails at the sides and is easy to ascend or descend except when the roof is at the bottom of the tank.

(2) **Ladder fixed to Roof.** Floating roofs in shallow tanks may be equipped with vertical ladders fastened at the lower end to the roof. The ladder extends above the tank shell as the roof rises. Such ladders are not as easy to climb as ladders of the rolling-stair type but are less expensive.

(3) **Pipe Ladder with Guide Sleeve.** On tanks having a small diameter and a great height, a fixed ladder made up of two vertical pieces of pipe with horizontal rungs between is sometimes used. The ladder is connected to the top of the tank shell and is held in place on the tank-bottom by means of a guide which permits some radial movement. The ladder passes through an oval-shaped guide sleeve in the roof.

(4) **Chain Ladders.** Various chain ladders have been devised and tried, but they have not proved to be very successful. Such ladders are not only difficult to ascend and descend but they frequently stick owing to the chain becoming fouled.

Guiding Device

A guiding device must be provided to prevent the floating roof from rotating in the tank. This device may consist either of a roller guide with a flanged wheel which runs on a vertical bar welded to the tank shell, or of a slotted guide shoe of the type illustrated in Fig. 3.

Gauging Methods

Tanks equipped with floating roofs may be gauged with an accuracy equal to that for tanks with fixed roofs. The preparation of the gauge table and the method of taking measurements will depend on the type of floating roof used. The gauge table really consists of two parts, one for the range in which the roof is on the supports, and the other for the range in which it is floating.

When the roof is on the supports the measurement is made from the tank-bottom to the liquid surface. This applies to all types of floating roofs. Allowance is made in the gauge table for the volume occupied by roof supports and for the volume of oil displaced by the roof in the small range during which liquid is in contact with the roof but not causing it to float. Better accuracy for this part of the table can be secured if a calibration is made by introducing known quantities of oil from another tank from the point where liquid first touches the roof to the point where it is fully floating.

The type of measurement used when the roof is floating will depend on whether or not the roof is constructed to trap vapour.

(1) **Roofs not designed to trap Vapour.** Roofs of the Pan type or the Double-deck Pontoon type constitute stable floats and the best results are secured by taking gauge measurements from the tank-bottom to the top of the gauge hatch, or from the gauger's platform at the top of the tank to some fixed point on the roof. When this procedure is followed, it is unnecessary to make corrections for ordinary water or snow loads on the roof or for changes in the gravity of the oil on which it is floating. A load on the roof tends to make it sink lower, but this is compensated by the rise of the oil in the rim space and the actual change in elevation of the roof is negligible. In preparing the gauge table provision should be made for the volume of oil displaced by the roof and for the type of measurement to be used so that the volume of oil corresponding to a given observation can be read directly.

(2) **Roofs constructed to trap Vapour.** Tanks equipped with Wiggins Pontoon Roofs are gauged by taking measurements from the bottom of the tank to the liquid surface in the gauge hatch. As the volume of the vapour under the deck varies the roof rises and falls, but the level of the liquid in the gauge hatch remains constant, a fact that may be demonstrated either analytically or experimentally. The gauge table is prepared in the same manner as a table for a cone-roofed tank. To determine the quantity of oil in the tank a volume of oil equivalent to the floating weight of the roof plus any water or snow load that may be on it is deducted from the volume in the gauge table corresponding to the observed measurement.

Savings made by Floating Roofs

The rate of evaporation loss from a tank having a fixed roof depends on a number of variable factors, including volatility of the stored product, climatic conditions, size of vapour space, type of roof vents, and colour of tank. In the United States cone roofs are ordinarily equipped with vents operating at ½-oz. pressure or vacuum, and it has been fairly well established that the standing storage loss from tanks containing motor gasoline averages from 2·5 to 3% of the tank capacity per year, whereas the filling loss averages about 0·2% of the quantity of gasoline handled.

By comparison, the annual standing storage loss from a tank equipped with a Wiggins Pontoon Roof will average from 0·5 to 0·8% of the tank capacity and the filling loss will not exceed 0·01% of the volume handled.

EVAPORATION LOSSES OF PETROLEUM AND GASOLINE

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Introduction

EVAPORATION of crude petroleum and gasoline is probably one of the most important sources of loss to the oil industry, and certainly it is one of the most insidious. The deceptive features of these losses are due to the relatively large coefficient of expansion of oil which frequently results in a change of several per cent. in volume during the normal range of yearly temperatures. This physical characteristic, together with the inaccuracies inherent in gauging, measuring, and sampling large volumes of liquid, often tend to conceal the appreciable evaporation that is taking place. The magnitude of these losses becomes apparent when the observations are continued over a long period of time.

Losses of Evaporation

A very careful and complete survey of the evaporation losses of crude petroleum from the well to the refinery was made during the years 1920–1 by J. H. Wiggins, and the results of this survey were published in Bureau of Mines Bulletin 200, entitled *Evaporation Loss of Petroleum in the Mid-Continent Field.* The summary of the findings by Wiggins is given in Table I.

TABLE I

Summary of the 1920–1 Evaporation Survey of the Bureau of Mines, showing the Average Evaporation Losses of Crude Petroleum during the Various Stages of Handling in the Mid-Continent Fields

Location of loss	*Average percentage evaporated*
Flow tank	1·0
Filling lease tank	1·0
Lease storage	1·5
Gathering systems	1·0
Transportation	1·0
Tank farms	0·7
Total	6·2

The figures in Table I are based upon the results of actual field tests on various types of tanks and equipment in general use at that time. When this survey was made, vapour-tight tanks and other evaporation-reducing methods were almost unknown in the oilfields. Field tests made during the past few years by the U.S. Bureau of Mines [8, 1934] indicate that a similar survey made to-day would show an average reduction of about 68% in the evaporation loss between the well and the refinery, even though the average volatility of the crude oil handled in the Mid-Continent area has increased within the past few years. The increase in the volatility of the crude oils handled is the result of the development of fields that produce oil of a lighter initial gravity and the retention of light fractions in the oil at or near the wellhead through improved methods of handling.

Losses of gasoline by evaporation at refineries have also, during the past several years, been greatly reduced by improved equipment and methods of operation. A survey in 1923–4 by the writer [7, 1925] showed an average evaporation loss of 6·3% of the gasoline, or approximately 2·1% of the total crude oil throughput at that time. Recent tests on new and improved equipment show that the evaporation losses in the refinery operations have likewise been reduced approximately 68%.

The magnitude of evaporation losses of crude petroleum and gasoline, as well as the importance of reducing these losses, is best shown in dollars and cents. For example, in 1934 the total crude oil production in Oklahoma and Kansas was about 227,179,000 bbl. [6, 1935]. The evaporation surveys by the Bureau of Mines, discussed in preceding paragraphs, show that with the old methods of handling oil there would be an average loss of 6·2% from the time crude oil leaves the well until it is received at the refinery, and an evaporation loss of 2·1% in the refinery, a total loss of 8·3%, or about 18,937,000 bbl. per year. However, a conservative estimate at this time shows that, with improved equipment and methods of operation, evaporation losses have been reduced 68% of the 8·3%, the equivalent of 12,877,000 bbl. Assuming the average market value of the oil saved to be 90 cents per barrel, the total saving for 1934 would be about $11,589,000 in Oklahoma and Kansas alone. This figure is based upon volumetric loss alone and does not consider the increase in the value of the crude oil by the change in gravity. From a conservation viewpoint the actual saving is much greater because the fractions lost through evaporation are the most volatile and most valuable gasoline constituents of the crude oil. Assuming the average tank-car value of the gasoline to be 4 cents per gallon or $1.68 per barrel, the total saving due to improved equipment and operating methods in Oklahoma and Kansas in 1934 would be about $21,633,000.

Theory of Evaporation

A detailed discussion of the theory of evaporation is not warranted in an article of this length; however, a short review may be of help to those interested in this problem.

Evaporation, in its broadest sense, may be defined as the change by which any substance is converted from a liquid or solid phase and carried off in a vapour phase. There are many general classifications of the methods of evaporation; however, most authorities make a separate classification for solar evaporation. Since the evaporation of the more volatile constituents of crude petroleum and gasoline is caused by the effect of solar heat plus other atmospheric conditions, it is therefore classed as natural or solar evaporation and may be defined as the slow forming of a vapour on the surface of the liquid. Ebullition, although to a somewhat lesser degree, is responsible for evaporation losses of petroleum, especially the losses occurring on the producing property where the crude oil coming directly from the well is often saturated with gas in solution.

Four of the principal factors which govern the rate of evaporation of a given liquid are:

1. The temperature of the surface of the liquid.
2. Area of the evaporation surface.
3. Quantity of same vapour in the surrounding atmosphere.
4. Renewal of air over the evaporating surface.

The vapour pressure of the liquid is controlled by the temperature; thus an increase in the temperature of the surface of the liquid increases the vapour pressure and increases the rate at which the liquid vaporizes.

The influence of the area of the evaporation surface upon evaporation is apparent, for it is evident that the same amount of a given liquid will evaporate more quickly in an open, shallow pan than if placed in a container in which the fluid depth would be greater, other conditions being the same.

The quantity of the same vapour in the surrounding atmosphere influences the rate of evaporation because in a closed container evaporation of a liquid will cease when the vapour space becomes saturated with the vapour of the liquid in the container. Thus the rate of evaporation of a liquid is directly proportional to the difference between the vapour pressure of the evaporating liquid and the pressure of the same vapour in the surrounding atmosphere.

The fourth factor—the renewal of air over the evaporating surface—is closely related to the third; a constant stream of unsaturated air over a liquid provides the rapid replacement of the saturated air with unsaturated air, so that evaporation is continuous.

The prevention or reduction of the rate of the evaporation of a liquid requires the control of one or more of the above listed factors. In actual practice a combination of two or more of the factors is regulated.

The following fundamental laws pertaining to the action of gases and vapours are useful in the study of evaporation losses: Boyle's law, which states that at a constant temperature the volume of a gas is inversely proportional to the pressure; and Charles' law, which states that at constant pressure the volume of a gas is directly proportional to its absolute temperature. Gases deviate from these laws appreciably at higher temperatures and pressures; however, in evaporation studies they may be applied safely without the use of correction factors as the deviations are very small at ordinary temperatures and pressures. Another law of importance in the study of evaporation is Dalton's law of partial pressures, which, briefly stated, is that the total pressure of a mixture of gases equals the sum of the individual pressures that each would exert if it alone occupied the same space, or in other words, the pressure of a gas which saturates a given space is the same for the same temperature, whether or not there are other gases or vapours in the same space.

Methods for Determining Evaporation Losses

There are many methods for determining the evaporation losses from crude petroleum and gasoline. They may be divided into three general groups: (1) The actual volumetric measurement of the liquid in a tank at given periods; (2) the determination of the changes in the physical characteristics of the liquid; and (3) measuring the vapours escaping from the tank during the test period. Although each group has its limitations as well as its merits, the choice of the method used depends to a large degree upon the test conditions (for example, the third method could not be used on tanks equipped with floating roofs). The writer usually used two or more independent methods to check each other.

Space does not permit a detailed discussion of the various methods used to determine evaporation losses; however, the following brief outline may be of value to those contemplating evaporation tests. More complete details are given in a previous publication by the writer [8, 1934].

The actual measurement of the volume of the liquid in the tank at stated intervals during the test period is probably the method most generally used in the field because the losses may be measured with a good degree of accuracy and extensive laboratory facilities are unnecessary, also the results are given directly in terms of volumes and do not require interpretation. Briefly, the method consists of gauging the tank to determine the amount of liquid it contains, obtaining the average temperature of the liquid at the time the gauge reading is taken, and correcting the volume for expansion due to temperature changes.

The determination of the changes in the physical characteristics of the oil require average samples of the liquid in the tank to be obtained at stated intervals during the test period and the change in certain of its physical characteristics to be measured. The physical characteristics usually measured are specific gravity, distillation curves, and vapour pressures. Probably the simplest of the physical characteristics to determine is the change in specific gravity. In evaporation tests the specific gravity is usually determined with a Westphal balance, the liquid being brought to a temperature of 60° F. in a water bath at the time of the readings. The percentage of the evaporation loss is calculated from the following formula:

$$x \quad \frac{d_2 - d_1}{d_2 - d_3},$$

where

x = fraction of original volume which has evaporated,
d_1 = specific gravity of the oil before evaporation,
d_2 = specific gravity of the oil after evaporation,
d_3 = specific gravity of the fraction evaporated, determined from distillation curves.

The use of the above formula and the determination of the evaporation losses from distillation curves are discussed in detail by Wiggins [11, 1922].

Several methods are used to determine the evaporation losses of crude petroleum and gasoline by measuring the change in the vapour pressure of the liquid. Probably the best known and most generally used vapour-pressure method was developed by Messrs. Stauffer, Roberts, and Whitman [10, 1930].

There are two general methods for the determination of evaporation losses by measurement of the vapours given off from the tank. The first method consists in measuring the vapours by meters and determining the gasoline content of the air-vapour mixture. There are many difficulties to overcome with this method; however, Case [2, 1933] has reported successful tests on 80,000-bbl. gasoline storage tanks.

The second method is based upon continuous records of temperature variations within the vapour space of the tank plus the determination of the gasoline content of the air-vapour mixture. Wilson, Atwell, and Brown [13, 1925] computed the theoretical evaporation losses from gasoline in large storage tanks from data showing the temperature variations in the vapour space in the tank. The amount of gasoline in the air-vapour mixture was determined from vapour-pressure curves of the gasoline in the tank. Delaney [3, 1927] reported evaporation test on 10,000-gal. gasoline storage tanks in which the gasoline content of the air-vapour mixture was determined by laboratory analysis. Similar methods discussed by the writer [8, 1934] were used by Paul L. Guarin in evaporation tests on 80,000-bbl. crude-oil storage tanks.

Reducing Evaporation Losses

Vapour-tight tanks with vacuum and pressure-relief valves and vapour-tight gauge and thief hatches is one of the principal methods used to reduce evaporation losses. With this type of tank construction the unrestricted flow of fresh air over the evaporating surface of the liquid in the tank is eliminated. However, with this type of equipment there is a constant renewal of air over the surface of the liquid which may result in two general types of evaporation losses. The first, often referred to as 'working losses', is caused by the filling and emptying of the tank with the liquid. As the tank is emptied, fresh unsaturated air is drawn into the tank, the air becomes saturated with gasoline vapours, and the air-vapour mixture is expelled to the atmosphere as the tank is filled with petroleum.

The second general type of evaporation loss may be defined as 'standing storage loss' or 'breathing loss'. The 'breathing' of the tank is due to the change in the pressure within the vapour space of the tank due to changes in atmospheric conditions plus the change in the vapour pressure of the liquid due to change in temperature. For example, during the night, as the atmospheric temperatures decrease, the vapours in the tank are cooled, which causes them to contract; thus a reduction of the pressure within the tank occurs and fresh unsaturated air is drawn in from the atmosphere. The pressure within the vapour space of the tank is also materially reduced during this period, due to reducing the temperature of the liquid surface, causing a reduction in the vapour pressure. During the day the reverse action takes place; as the temperature in the vapour space increases, the pressure increases due to volumetric expansion and increase in vapour pressure of the liquid. This total increase in pressure within the vapour space of the tank causes the air-vapour mixtures to flow from the tank into the atmosphere.

The 'working' and 'breathing' or 'standing storage' losses may be materially reduced by reducing the temperature and temperature variation in the vapour space and operating the tank under pressures higher than the atmospheric pressure. For most economical operation usually a combination of the above two are used. Reducing the area of the evaporation surface per barrel of oil stored as well as the vapour space is also helpful.

These losses may be reduced to a minimum by the use of special types of tank construction such as floating roofs, breather-type roofs, high-pressure storage tanks, and also by vapour-saving methods such as breather bags and steel balloons and vapour-recovery methods; however, because of cost of equipment or operation these have definite economic limitations.

Reduction of Evaporation Losses from Vapour-tight Tanks

The value of vapour-tight tanks in reducing evaporation losses is so well recognized to-day that they are now considered standard equipment for storing crude oil and gasoline. However, there are several factors in connexion with their selection and operation which so influence the rate of evaporation that they are worthy of some discussion.

The first of these is selecting the size of tank commensurate with the volume of liquid to be handled. For example, a lease producing 10 bbl. of oil per day equipped with 100-bbl. stock tanks would turn over to the pipeline a full tank every 10 days. The first day's production would fill the tank to a depth of approximately 10 in., the evaporating surface per barrel stored would be approximately 6·69 sq. ft., and the total vapour space approximately 490·4 cu. ft. By the 9th day the total evaporating surface per barrel stored would have decreased to 0·73 sq. ft. and the total vapour space to 41·22 cu. ft. If the lease were equipped with 250-bbl. tanks it would require 25 days to fill the tank and the first day's production of 10 bbl. would fill the tank to a depth of about 0·30 ft. or approximately 3⅝ in. The total evaporating surface per barrel of oil stored would be about 18·59 sq. ft. with a total vapour space of 1,478·66 cu. ft., and by the 9th day the evaporating surface per barrel of oil stored would be 2·07 sq. ft., approximately 2·83 times that of a 100-bbl. tank for the same volume of oil, and the total vapour space would be 1,029·46 cu. ft., or about 25 times greater for the same volume of liquid in the 100-bbl. tank. The calculations above are based on the A.P.I. Dimensional Specifications for Standard Bolted Tanks, A.P.I. Standards 12-B, 1931.

That the volume of vapour space above the surface of the liquid in a tank has a material effect on the evaporation loss is shown by the results of evaporation tests on two groups of steel storage tanks containing gasoline. The results [7, 1925] are shown in Table II. The tanks were all steel, but they would not be considered vapour-tight according to present-day construction; however, they were similar in so far as tightness and tank equipment were concerned. All of the tanks were in the same locality and the tests made during the same season of the year.

TABLE II

Comparative Data from Evaporation Tests on 10,000-bbl. and 25,000-bbl. Tanks containing Gasoline

	Tanks with 10,000 bbl. capacity	*Tanks with 25,000 bbl. capacity*
Average evaporation loss per day	6·44 bbl.	6·78 bbl.
Average gravity of gasoline	63·1° API.	60·1° API.
Average temperature of gasoline during test period	67·2° F.	67·9° F.
Height of tanks (shell)	30 ft. 3 in.	30 ft. 3 in.
Diameter of tanks	50 ft. 0 in.	77 ft. 6 in.
Approximate capacity of tanks	10,580 bbl.	25,450 bbl.
Area of liquid surface	1,963 sq. ft.	4,717 sq. ft.
Vapour space above liquid level	9,625 cu. ft.	11,256 cu. ft.
Cubic feet of vapour space per square foot of evaporating surface	4·9	2·4

All the tanks were filled to approximately the same height; therefore the number of barrels stored per square foot of evaporating surface were approximately the same for both sizes of tanks. Table II shows that each 10,000-bbl. tank had an evaporating surface of 1,963 sq. ft., and each of the 25,000-bbl. tanks an evaporating surface of 4,717 sq. ft.; therefore, other conditions being equal, the daily rate of evaporation from the 10,000-bbl. tanks should be approximately 0·4105 times that from the 25,000-bbl. tanks or 2·78 bbl. per day. However, the 10,000-bbl. tanks were equipped with globe or umbrella roofs providing a vapour space above the gasoline of 4·9 cu. ft. per square foot of evaporating surface, whereas the 25,000-bbl. tanks were equipped with cone roofs which provided a vapour space of 2·4 cu. ft. per square foot of evaporating surface. Therefore, when 'breathing', the 10,000-bbl. tanks expelled twice as much air-vapour mixture per square foot of evaporating surface as the 25,000-bbl. tanks. Taking this factor into account, the loss to be expected from the 10,000-bbl. tanks

is twice 2·78 or 5·56 bbl. per day. However, the observed evaporation loss from the 10,000-bbl. tanks as shown in Table II was 6·44 bbl. per day or 0·88 bbl. more than the loss to be expected if the evaporation from the 25,000-bbl. tanks is taken as a basis. This difference was probably due to the somewhat more volatile gasoline in the 10,000-bbl. tanks.

Vacuum and Pressure-relief Valves

Equipping vapour-tight storage tanks with vacuum and pressure-relief valves, even though operating at very low pressures, appreciably reduces the evaporation losses. The reduction in the evaporation loss is due to the valve preventing the flow of air-vapour mixture from the tank caused by minor variations in atmospheric conditions. The valve also eliminates diffusion of vapours through vent-lines, as well as losses of gasoline vapours due to the siphoning action of vent-lines as described by Wilson, Atwell, Chenicek, and Brown [14, 1925].

The value of vacuum and pressure-relief valves is shown by the following evaporation test on two 37,500-bbl. vapour-tight tanks containing crude petroleum having a gravity of 37·1° API. One of the tanks was equipped with an 8-in. vacuum and pressure-relief valve and flame arrester operating at ½-oz. pressure, and the other tank was equipped with an 8-in. flame arrester and a free vent. Both tanks were filled at the same time. The tank with the free vent contained 34,993 bbl., and the tank equipped with the relief valve contained 34,723 bbl. of crude petroleum. After a 14-month test period the tank with the free vent had lost by evaporation 199 bbl. or 0·57%, and the tank equipped with the vacuum and pressure-relief valves had lost only 152 bbl. or 0·44%, making a saving of approximately 25%.

That the saving is even greater on tanks containing more volatile crude petroleum is shown by an evaporation test on two all-steel vapour-tight 80,000-bbl. tanks containing approximately 76,000 bbl. of crude oil each of an average gravity of about 39·1° API. One tank was equipped with two 6-in. vacuum and pressure-relief valves operating at about ½-oz. pressure, and the other with a breather line extending from the top of the tank through the fire dyke to a 7-ft. riser equipped with fire screens. After a 9-month standing-storage test period, the tank with the breather line showed an evaporation loss of 464 bbl. or 0·61%, whereas the tank equipped with relief valves showed an evaporation loss of only 295 bbl. or 0·39%, or a saving of about 36%.

Light-coloured Paints, Insulation, and Water-cooling Methods

Light-coloured paints, insulation, and water-cooling methods further reduce evaporation losses from vapour-tight tanks by limiting certain of those factors which promote 'breathing' and which control the amount of petroleum or gasoline vapours in the air-vapour mixture above the liquid in the tank.

The value of light-coloured paints is discussed in more detail in another article by the writer on page 834 of this publication; however, the following test results show the value of light-coloured paints and one type of insulation. The results of a comparative evaporation test by the writer and C. J. Wilhelm [9, 1931] on four 12,000-gal. welded vapour-tight gasoline bulk-storage tanks is given in Table III. All of the tanks were set horizontally, and were equipped with pressure- and vacuum-relief valves operating at 2-oz. pressure and ½-oz. vacuum and vapour-tight gauge and thief hatches. The tanks were filled with gasoline having a gravity of 64·8° API., and on distillation gave the first 10% over at 133° F. with an end-point of 419° F. Tank no. 1 was painted white, and in addition the top and upper half of the tank were protected with an insulated housing of corrugated asbestos cement sheets attached to a welded steel frame. Tank no. 2 was covered with aluminium foil. Tank no. 3 was painted with aluminium paint, and tank no. 4 was painted red. The test period was from 29 May to 15 October.

TABLE III

Results of Comparative Evaporation Tests on Four 12,000-gal. Horizontal Gasoline-storage Tanks

Tank no.	Description	Evaporation losses		Loss in gravity ° API.
		Gallons	%	
1	Painted white and protected with insulated housing	112	1·40	0·45
2	Covered with aluminium foil	170	2·12	0·55
3	Painted with aluminium paint	187	2·34	0·62
4	Painted red	284	3·54	0·89

Table IV shows average vapour-space temperatures in each test tank for the month of July during the test period.

TABLE IV

Summary of the Vapour Temperatures obtained in the Test Tanks during the Month of July

Tank no.	Average temperature			Temperatures	
	Maximum, ° F.	Minimum, ° F.	Daily variation, ° F.	Maximum, ° F.	Minimum, ° F.
1	97·0	72·7	24·3	110·0	59·0
2	108·4	77·4	31·0	120·6	67·0
3	113·6	78·7	34·9	126·0	67·1
4	130·0	76·2	53·8	148·0	62·0

During this period the atmospheric temperature data, according to the U.S. Weather Bureau, was as follows: maximum 104° F., minimum 59° F., mean temperature 82·8° F., greatest daily variation 31° F., and there were 410 hours of sunshine, the total possible sunshine hours being 452·6 hours.

Water-cooling methods are usually restricted to those areas where water is both plentiful and cheap. The use of various types of water-sealed roofs and water sprays greatly reduces the vapour temperature, as well as the surface temperatures, of the liquid within a tank. For example, Table V shows the average vapour temperatures recorded in three 250-bbl. tanks containing gasoline. One tank was equipped with a water spray and one with a water-sealed roof, and the third tank had no cooling system.

TABLE V

Vapour Temperatures in Water-sprayed, Water-sealed, and Non-cooled Tanks for a 12-day period during the Month of July

	Water-sprayed tank	Water-sealed roof	Non-cooled tank
Average maximum temperature, ° F.	94	98	125
Average minimum temperature, ° F.	77	89	79
Average temperature, ° F.	82	93	102
Average daily variation, ° F.	17	9	46

At the end of a 2-weeks' period of summer temperatures the surface temperature of the gasoline in the non-cooled tank was 108° F., in the tank with the water-sealed roof the surface temperature of the gasoline was 96° F., and in the water-sprayed tank the surface temperature was only 89° F.

An evaporation test made on these tanks during the spring and early summer months showed that after an 85-day test period the non-cooled tank lost 1·54%, the water-sealed tank 0·9%, and the water-sprayed tank 0·65%.

Special Types of Tank Construction

There are now in use tanks designed to operate at pressures ranging from a few ounces per square inch to 50 lb. per sq. in. with a capacity of 10,000 bbl. Tanks with a capacity of 80,000 bbl. and an operating pressure of 10 lb. per sq. in. are also in use. In tanks of this type there can be no evaporation when the tanks are full, provided the pressure developed within does not exceed the working pressure of the tank; moreover, the filling losses are materially reduced.

The vapour space is practically eliminated in tanks equipped with floating roofs as the roof rides on the surface of the liquid. Although tanks equipped with floating roofs are considerably more expensive than the all-steel vapour-tight tank, they have proved to be economically successful for tanks which are constantly being filled or emptied; for example, pipeline working tanks and 'run-down' tanks in refineries.

More detailed discussion of pressure tanks and floating roofs are given elsewhere in this report [5].

'Breather' Roofs for Petroleum Storage Tanks

The diaphragm or 'breather' roof is a distinctive type of tank construction which virtually eliminated movement of air-vapour mixture from a storage tank filled with oil.

The breather roof is an all-steel riveted or welded roof which slopes downwards from its outside circumference towards the centre for about 20 ft. in an 80,000-bbl. tank and then is level to the centre, forming an inverted frustum of a cone with an altitude of about 8 in. To provide for greater altitude of the frustum of the cone, or in other words, greater expansion of the roof when inflated, excess metal is provided in the roof during construction by blocking up the centre post of the tank so that the rafters at the centre of the tank are about 1 in. below the top angle iron. The second ring of posts is also blocked up. Thus, if the tank were cut into through the middle, the rafters would have the shape of a large flat W. After the roof is completed the extra blocks beneath the centre column and middle posts are removed, and the roof and framing are lowered to their normal position. This method of construction permits a rise of 24 in. in the centre of a tank 117 ft. in diameter, providing a volumetric expansion of 11,000 to 12,000 cu. ft. for the vapour space in the tank. For a smaller tank it is less; for example, the rise in a tank 60 ft. in diameter is about 20 in.

Breather-type roofs are provided with direct-action mechanical volume-control valves and are opened by means of a mechanical trip which engages the roof framing when the roof has risen to a predetermined height. A vacuum-relief valve of the liquid seal type as well as a liquid seal gauge and thief hatch and gauge well are also provided to prevent the escape of vapours from the tank during gauging operations.

Evaporation tests reported by the writer [8, 1934] show the value of this type of construction as compared with a vapour-tight tank equipped with vacuum and pressure-relief valves and one equipped with breather lines. All the tanks contained crude petroleum. The test period was for 11 months and the results are given in Table VI.

TABLE VI

Results of a Comparative Evaporation Test of a Breather-roof Tank, a Cone-roof Tank with Vacuum and Pressure-relief Valves, and a Cone-roof Tank with Breather Lines

Type of roof	*Capacity of tank, bbl.*	*Evaporation loss*		*Loss in gravity, ° API.*
		Barrels	*%*	
Breather . . .	80,000	39–79	0·05–0·1	0·06
Cone, welded, with relief valves . . .	55,000	242	0·46	0·2
Cone, riveted, with breather lines . .	80,000	749	0·95	0·5

The evaporation loss from the tank equipped with the breather roof, given in Table VI, was from 39 to 79 bbl. Gauge readings from this tank were difficult to obtain as it was equipped with a gauge well and every movement of the roof caused the liquid in the gauge well to rise or fall. The continuous motion of the roof due to wind pressures and temperature variations caused constant variation of the liquid in the gauge well ranging from ¼ to ¾ in. The results covering barrels evaporated, therefore, are obtained from average mean maximum and minimum gauges.

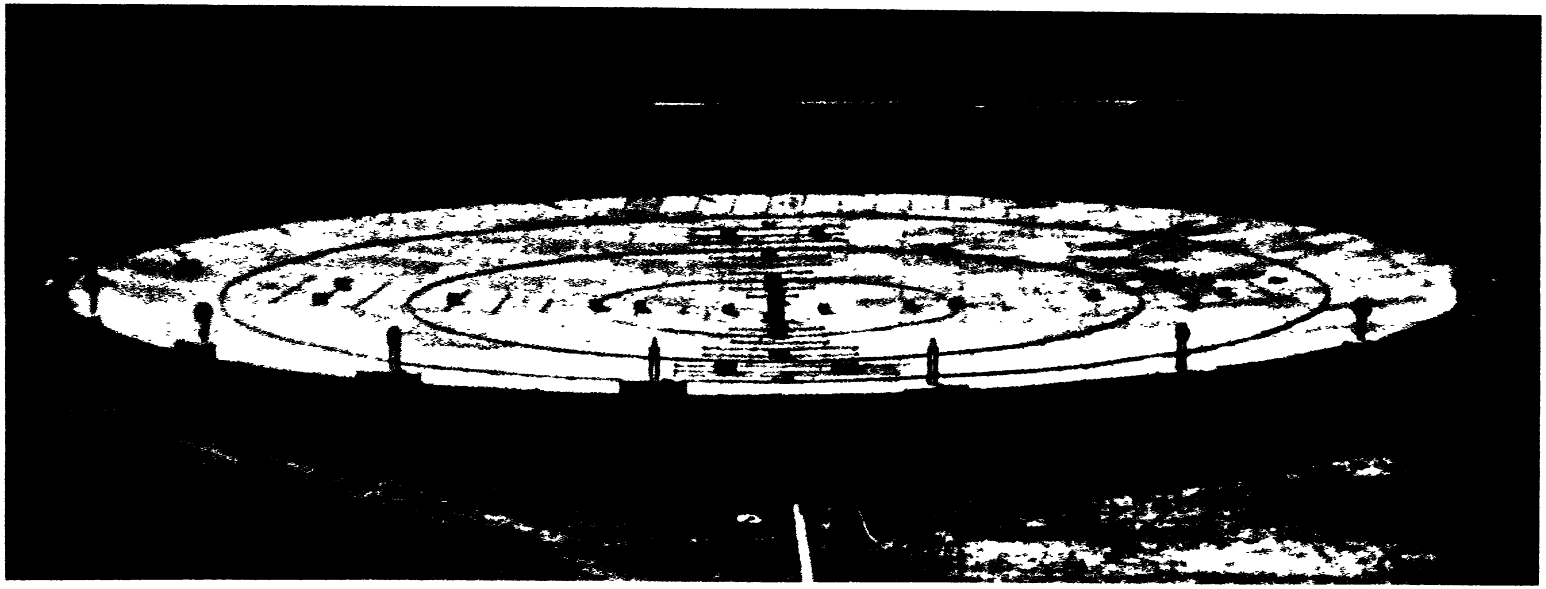
Although the breather-roof tank contained a more volatile crude (gravity 42·2° API.) than the other two (gravity 40·1° API.), this handicap is offset somewhat by the gauge well, because it prevented the loss of any vapours from the breather-roof tank during gauging. Neither cone-roof tank had gauge wells.

Breather Bags and Steel Balloons

Breather bags and steel balloons may both be classified as vapour-saving equipment, and in operation they are essentially the same, namely, the balloon or bag is connected to the vapour space of one or more oil-storage tanks, so that during the day, as the tank is 'breathing' out, the vapours are collected in the balloon, and at night, when the atmosphere is cooler, the tank 'breathes' in and the vapours are returned to the tank. It is not economical to install balloons of sufficient capacity to care for the total air-vapour requirements when tanks are filled or emptied. However, several working tanks are often connected to a balloon which acts as a balance chamber, thus greatly reducing the amount of air-vapour mixture that would otherwise be expelled to the atmosphere.

Breather-bag installations have been described in detail by Messrs. Wilson, Atwell, and Brown [3, 1927], and they also give results of tests on 65,000-bbl. gasoline storage tanks showing evaporation losses of 0·25% per month from tanks not equipped with breather bags as compared with losses of 0·04% per month from tanks connected to breather bags.

Fig. 1 shows a 150,000-cu. ft. steel balloon installed with necessary counterbalances. This balloon is connected to 5–80,000-bbl. crude-oil tanks equipped with breather roofs. This particular installation is part of a crude-oil gathering and field-storage system, approximately 15,000 bbl. of crude oil being handled daily. Unfortunately, no evaporation tests are available on this installation, although charts



By the courtesy of J. H. Wiggins

FIG. 1. Steel balloon. 150,000 cubic foot capacity

of recording pressure-gauges furnished the writer showed that during a 30-day test period the balloon vented to the atmosphere 7 times and then for only very short periods of time. L. G. E. Bignell [1, 1933] discusses the details of the use of steel balloons with especial reference to reducing interior corrosion of storage systems.

Vapour-recovery Systems

Space does not permit a detailed discussion of vapour-recovery systems for the various types of installation and operation which are quite involved. In general, however, such systems are usually found in refineries. Usually all the storage and run-down tanks are connected into a vapour-gathering system and the gasoline extracted at a natural gasoline plant. In some refineries the crude petroleum is 'debutanized' before it is run to the stills [12, 1929].

A detailed discussion of plants for the recovery of gasoline from uncondensed still vapours is given by D. B. Dow [4, 1923]. Installations of this type are adaptable for vapour-recovery plants for the refinery.

Conclusions

It is not possible in a paper of this length to go into all of the details of the various methods of reducing evaporation losses. The writer has attempted to confine his discussion to the principal factors involved, giving actual test data to show the results obtained with various methods.

It should be pointed out that only by careful study of each individual problem is it possible to select the most economic method for reducing evaporation losses. Irrespective of the method selected, the maximum results can be obtained only by regular and careful inspection of equipment.

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EFFECT OF TANK COLOURS FOR REDUCING EVAPORATION LOSS FROM CRUDE PETROLEUM AND GASOLINE STORAGE TANKS

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Introduction

THE use of light-coloured paints, insulation, and water-cooling for reducing evaporation losses from crude petroleum and gasoline storage tanks is generally recognized as one of the most economical methods for reducing evaporation losses from vapour-tight tanks equipped with vacuum and pressure-relief valves and vapour-tight gauge and thief hatches.

The choice of paints for tanks used in the oil industry involves many factors, probably the three most important being cost, protective value, and colour. Many companies have adopted a standard colour for all tanks, thus reducing the cost of materials by buying in large quantities. Unfortunately, most paints used to protect steel from corrosion are of the darker colours, usually red or black. These colours absorb solar heat and accelerate the rate of evaporation of oil in the tanks. Within recent years special metal-protecting primers to be used under light-coloured cover coats have been marketed by several paint manufacturers. In many fields producing hydrogen sulphide in conjunction with crude petroleum and natural gas, especial consideration has to be given to the selection of paint for oil-storage tanks. Hydrogen sulphide gas, in addition to accelerating the corrosion of iron and steel, also attacks paints, often causing discoloration of the paint and the destruction of the paint film.

Theory

The temperature of the liquid and vapours in oil-storage tanks is influenced chiefly by heat received from outside sources by radiation, the principal source being the sun. Radiant heat waves and light rays are similar in that both rays are reflected, absorbed, and refracted. Therefore, when radiant heat waves fall on a body, part of them are reflected, a portion is absorbed, and, if the body or substance is very thin or transparent, part are transmitted. Thus the nature and colour of a body determine the extent to which it will be heated by absorption of radiant heat waves.

The effect of colour upon the absorption and reflection of radiant waves from the sun has been of interest to students for many years. Quoting Ganot's *Physics* [1, 1910]:

> 'Nearly a century ago Franklin made experiments on coloured pieces of cloth, and found their absorption, indicated by their sinking into snow on which they were placed, to increase with the darkness of the colour.'

Several laboratory tests to determine the effect of colour upon the interior temperatures of oil- and gas-storage tanks were made by Gardner. Table I [2, 1917] gives the results of tests in which a carbon arc was used as the source for the heat waves.

In discussing the results of this test Gardner pointed out the fact that paints presenting a high gloss absorb less of the thermal rays than those presenting a matte surface.

TABLE I

Rise in Temperature of Benzine in Small Tanks painted in Various Colours (gloss finish), when subjected to the Rays of a Carbon Arc for 15 Minutes

Colour	Rise in degrees Fahrenheit
Tin plate	19·8
Aluminium paint	20·5
White paint	22·5
Light cream paint	23·0
Light pink paint	23·7
Light blue paint	24·3
Light grey paint	26·3
Light green paint	26·6
Red iron oxide paint	29·7
Dark prussian blue paint	36·7
Dark chrome green paint	39·9
Black paint	54·0

Table II gives the results of another test by Gardner [3, 1921] on small tanks of different colours exposed to the rays of the sun.

TABLE II

Effect of Colour on the Temperature and Percentage Loss by Volatilization in Small Tanks ⅞ filled with Naphtha and exposed to the Sun for 2 Hours

Colour of tank	Temperature of naphtha, ° F.	Loss of naphtha by volatilization, %
Black	111	9
Bright red	109	8
Dark red	108	8
Dark green	108	8
Battleship grey	106	6
Tan	104	5
Red primer– white top coat	102	5
Cream	102	5
Pale blue	102	5
White	100	4

In connexion with the above test Gardner points out that in areas in which large quantities of hydrogen sulphide gas are present in the atmosphere the finishing coats should be lead-free, because hydrogen sulphide gas acts rapidly upon paints containing lead, causing them to darken and thus show higher temperature factors. In addition, the liquid portion of the paints may be acted upon almost as fast as the pigment portion if traces of lead-drier are present. He suggested manganese driers where hydrogen sulphide gas is present.

Wiggins [6, 1923] reported temperature data for a 31-day test period on three oil-storage tanks, one of which was painted black, the second painted red, and the third white, as compared with the atmospheric temperature. His observations are summarized in Table III.

TABLE III

Temperatures observed in Three Oil-storage Tanks painted Black, Red, and White as compared with Atmospheric Temperatures for a 31-day Test Period

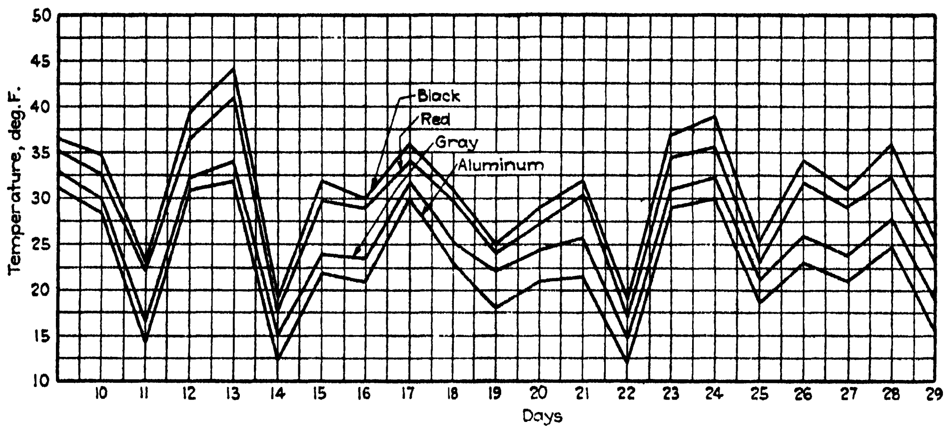
Colour of tank	*Average vapour temperature, ° F.*	*Average daily variation between maximum and minimum, ° F.*
Black	88	27
Red	85	25
White	75	18
Atmospheric temperature .	67	33

Effect of Tank Colours on Evaporation Losses

In 1924 the Bureau of Mines made a series of tests to determine the effect of tank colours on the evaporation losses from 55,000-bbl. storage tanks containing crude petroleum [4]. The tanks were of vapour-tight construction and each was equipped with 4 gauge hatches and 1 6-in. breather line extending outside the fire dyke and protected with fire screens. One tank was painted black, 1 red, 1 grey, and 1 aluminium.

During the test period the roof and part of the side of the aluminium-painted tank was covered with crude oil when a lead line broke on a near-by flow tank. The oil was not completely cleaned off for several weeks, therefore this tank was almost black during part of the test. Another factor tending to neutralize the heat-reflecting properties of the colours was the thin film of dust which covered the tanks during the hot, dry, summer months. This dust was usually oily, due to the large quantities of gas and oil vapour in the air, and clung to the tanks tenaciously.

Observations were made of the temperatures of the vapour spaces in each of the test tanks with recording thermometers. The graph shows the daily maximum variation in the temperatures of the vapour spaces in the tanks painted black, red, grey, and aluminium for a 20-day period during the month of August. This period most nearly illustrates the average temperature conditions during the test period. The temperature data in the graph show that light-coloured paints are most effective on clear days with bright sunshine. For example, on 14 August, a cloudy day with some rain, the total daily temperature variation in the vapour spaces of the four test tanks tended to equalize, whereas on clear, hot days (13 and 24 August) there were



Daily variations in temperatures recorded during 20 days in August in tanks painted black, red, grey, and aluminium.

The test tanks were located in the Burbank field, Oklahoma. They were filled with fresh crude oil pumped direct from vapour-tight lease tanks. At the beginning of the test the crude oil had an average gravity of 37·4° API. A distillation of an average sample of the crude oil by the Bureau of Mines Hempel method gave a gasoline and naphtha content of 29% with a gravity of 59·9° API. The test was for a period of 1 year. The results of the test given in Table IV therefore apply to average conditions throughout the year.

TABLE IV

Results of Evaporation Tests on Four 55,000-bbl. Storage Tanks containing Crude Oil and painted Black, Red, Grey, and Aluminium respectively

Colour of tank	*Initial gauge, bbl.*	*Evaporation loss in 1 year*		*Loss in gravity in 1 year, ° API.*
		bbl.	*%*	
Black . . .	52,058	649	1·24	0·6
Red . . .	53,294	609	1·14	0·5
Grey . . .	53,192	547	1·03	0·3
Aluminium . .	53,418	447	0·83	0·2

wide differences in the maximum temperature variations in the test tanks. However, for the period shown in the graph there is a material difference in the average daily temperature variation which is as follows: black 32° F.; red 29° F.; grey 25° F.; and aluminium 23° F. The average maximum temperature recorded during this same period is as follows: black 100·4° F.; red 108·5° F.; grey 103·8° F.; and aluminium 101° F.

The economic value of light-coloured paints for reducing evaporation losses in small lease tanks is shown by another series of observations by the Bureau of Mines on three 250-bbl. lease tanks [5, 1934]. One of the tanks was painted red, one aluminium, and the third protected with a wooden tank house. All the tanks were vapour tight and equipped with relief valves operating at 1 lb. pressure and 4 oz. vacuum. The wells on the lease where these tanks were located produced crude oil which varied in gravity from 35·6° API. to 36·7° API., the average being about 36° API. Although detailed evaporation tests were not made on these tanks, the economic value of the aluminium and housed tanks was shown by the pipeline gauge tickets of the crude oil run from the tanks. A complete record of the gauge tickets showed that during the months of May,

June, July, and August the average gravity of the oil run from the housed tank was 36·34° API. with 9% of the oil run under 36° API.; for the aluminium-painted tank the average gravity was 36·21° API. with 14% of the oil run under 36° API.; and the oil from the red tank had an average gravity of 36° API. with 37·5% under 36° API. These records show the economic value of light colours over dark for painting tanks as well as the value of tank houses in maintaining the gravity of the oil produced.

Table V gives a summary of the temperature data obtained from the test tanks during the month of May and is representative of average temperature conditions throughout the test period.

TABLE V

Comparative Temperature Data for the Month of May on Three 250-bbl. Lease Tanks operating under 16 oz. Pressure, one painted Red, one Aluminium, and the third equipped with Wooden Tank-housing

	Colour of tanks			
	Red	*Aluminium*	*Housed tank*	*Atmospheric temperature*
Maximum temperature, ° F.	127	112	101	93
Minimum temperature, ° F.	52	44	45	40
Average daily maximum temperature, ° F.	108	92	89	82
Average daily minimum temperature, ° F.	60	57	63	58
Average daily temperature variation in vapour space, ° F.	48	35	26	24
Average temperature of vapour, ° F.	84	74·5	76	70

Table V shows the average daily temperature variation in the aluminium-painted tank to be 13° F. lower than for the red tank. This differential is 7° F. greater than shown by the observations on the 55,000-bbl. test tanks given previously. There are several factors which may account for the differences between the average daily temperature variation. Probably the two most important are: the great difference in the volumetric capacities of the two groups of test tanks, the smaller tanks permitting a more rapid change in the temperature of the vapour as well as the liquid; and the fact that no oil-dust film collected on the surface of the test tanks.

Table V also shows the average daily minimum temperature for the housed tank to be 63° F., which is the highest average daily minimum of the three tanks. An explanation for the comparatively high minimum temperature for the housed tank probably depends upon the laws of heat absorption. During the day the wood absorbs heat from the sun; at night the heat is given off slowly, and some of it is taken up by vapours in the tank. This action tends to retard the cooling. Also, the housing prevents the cooling effect on the tank of occasional showers and of any dew or other moisture which collects on objects during the night.

Conclusions

The above tests, along with many others, show conclusively the economic value of light-coloured paints for reducing the evaporation losses from oil-storage tanks. The principal factor is to select a light-coloured paint that will satisfactorily maintain its colour and reflective properties under the operating conditions to which it is subjected. The comparative heat-reflecting value between the light colours or shades is probably not so material. For example, in Table III the difference in average daily temperature variation between the white tank and the black tank is 9° F., and the difference in the average daily temperature variation between an aluminium-painted tank and the black tank in the graph is also approximately 9° F.

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